



Working to Perfect the Flow of Energy

Style Definition: PJM_Bulleted_Outline_1:
Bulleted + Level: 1 + Aligned at: 0" + Indent
at: 0.25"

Style Definition: PJM_Normal: Font: (Default)
Calibri, Line spacing: Multiple 1.15 li

PJM Manual 11:

***Energy & Ancillary Services Market
Operations***

Revision: 510

Effective Date: ~~April 3, 2012~~

Prepared by

Forward Market Operations



Working to Perfect the Flow of Energy

Emergency Operations

Revision History

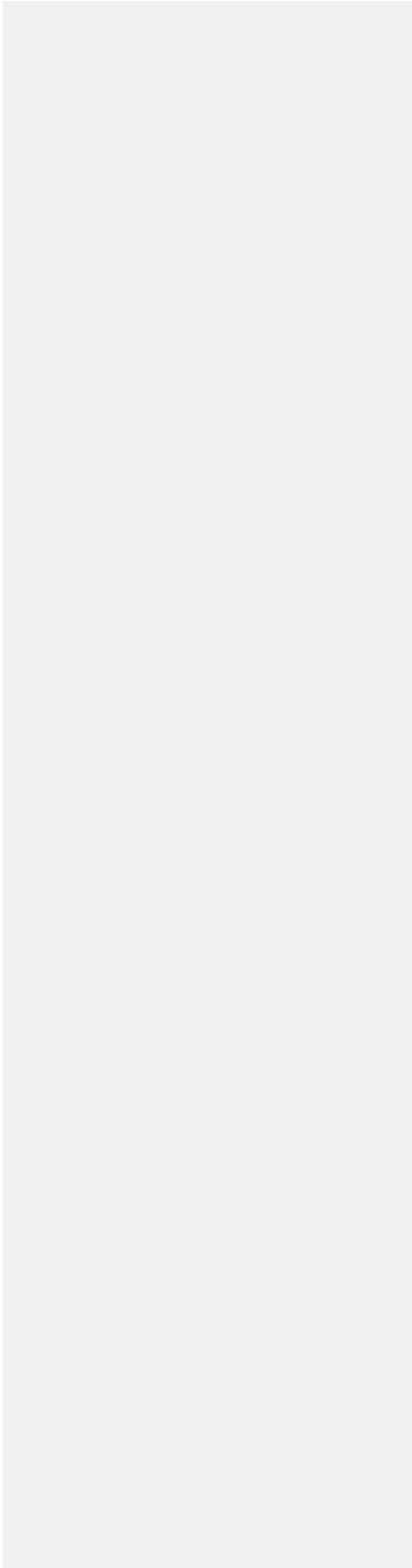




Table of Contents

Table of Contents.....iii

Table of Exhibitsxxxv

Approval.....36

Current Revision36

Introduction38

ABOUT THIS MANUAL 38

Intended Audience.....39

References.....39

USING THIS MANUAL 40

What You Will Find In This Manual.....40

Section 1: Overview of Energy & Ancillary Services Market Operations41

1.1 PJM RESPONSIBILITIES 43

1.2 PJM MARKET PARTICIPANTS RESPONSIBILITIES 44

1.2.1 Market Buyers.....44

1.2.2 Market Sellers.....46

1.2.3 Load Serving Entities.....46

1.2.4 Curtailment Service Providers.....46

Section 2: Overview of the PJM Energy Markets.....47

2.1 OVERVIEW OF PJM ENERGY MARKETS 47

2.2 DEFINITION OF LOCATIONAL MARGINAL PRICE48

2.3 ENERGY MARKET BUSINESS RULES 49

2.3.1 Bidding & Operations Time Line:.....49

2.3.2 Market Buyers.....50

2.3.3 Market Sellers.....51

2.3.4 Minimum Generator Operating Parameters – Parameter Limited Schedules.....56



[2.3.5 Curtailment Service Providers.....](#)62

[2.3.6 PJM Activities.....](#)62

[2.3.7 Mechanical/Technical Rules.....](#)63

[2.3.8 Modeling.....](#)65

[2.3.9 Day-ahead Locational Marginal Price \(LMP\) Calculations.....](#)65

[2.4 REAL-TIME LOCATIONAL MARGINAL PRICE \(LMP\) CALCULATIONS](#) 66

[2.5 UNIT DISPATCH SYSTEM](#) 67

[2.6 PJM STATE ESTIMATOR](#) 68

[2.8 LOCATIONAL PRICING ALGORITHM](#) 72

[2.9 PJM REAL-TIME LOCATIONAL MARGINAL PRICE VERIFICATION PROCEDURE](#) 75

[2.10 PRICE-BOUNDING VIOLATIONS](#) 76

[2.11 CALCULATION OF RAMP LIMITED DESIRED MWH](#) 76

[2.12 USING AND CALCULATING LOCATIONAL MARGINAL PRICES](#) 78

[2.12.1 Day-ahead Settlement.....](#)80

[2.12.2 Balancing Settlement.....](#)80

[2.13 BALANCING OPERATING RESERVE COST ANALYSIS](#) 81

[2.13.1 Maximum Emergency Generation in Day-ahead Market.....](#)83

[2.13.2 Minimum Capacity Emergency in Day-ahead Market.....](#)84

[Section 3: Overview of the PJM Regulation Market.....](#)85

[3.1 OVERVIEW OF THE PJM REGULATION MARKET](#) 85

[3.2 PJM REGULATION MARKET BUSINESS RULES](#)86

[3.2.1 Regulation Market Eligibility.....](#)86

[3.2.2 Regulation Market Data Timeline.....](#)88

[3.2.3 Regulation Bilateral Transactions.....](#)89

[3.2.4 Regulation Requirement Determination.....](#)89

[3.2.5 Regulation Obligation Fulfillment.....](#)90

[3.2.6 Regulation Offer Period.....](#)90

[3.2.7 Regulation Market Clearing.....](#)90

[3.2.8 Hydro Units.....](#)93



3.2.9 Regulation Market Operations.....94

3.2.10 Settlements95

Section 4: Overview of the PJM Synchronized Reserve Market.....96

4.1 OVERVIEW OF THE PJM SYNCHRONIZED RESERVE MARKET 96

4.2 PJM SYNCHRONIZED RESERVE MARKET BUSINESS RULES 97

4.2.1 Synchronized Reserve Market Eligibility.....97

4.2.3 Synchronized Reserve Requirement Determination.....99

4.2.4 Synchronized Reserve Obligation Fulfillment101

4.2.5 Synchronized Reserve Offer Period.....101

4.2.6 Bilateral Synchronized Reserve Transactions102

4.2.7 Synchronized Reserve Market Clearing103

4.2.8 Hydro Units.....105

4.2.9 Demand Resources106

4.2.10 Synchronized Reserve Market Operations106

4.2.11 Settlements107

4.2.12 Verification.....108

4.2.13 Non-Performance.....109

Section 5: Market Clearing Processes and Tools.....111

5.1 PJM PHILOSOPHY 111

5.2 SCHEDULING TOOLS 112

5.2.1 Enhanced Energy Scheduler (EES).....113

5.2.2 PJM eSchedules.....113

5.2.3 Load Forecasting.....113

5.2.4 Markets Database System.....115

5.2.5 Hydro Calculator.....118

5.2.6 PJM Energy Market Technical Software.....119



5.2.7 Synchronized Reserve and Regulation Scheduling Software (SPREGO) 122

Section 6: Reserve Requirements in PJM Energy Markets 124

6.1 FORECASTING PJM GENERATION REQUIREMENT 124

6.1.1 PJM Regulation Requirement..... 126

6.1.2 Regulation Service 128

6.2 PJM SYNCHRONIZED RESERVE REQUIREMENTS 131

6.2.1 Synchronized Reserve Service 132

6.3 PROCESSING MARKET INFORMATION 132

6.3.1 PJM Member Load Forecasts 132

6.3.2 Reserve Service 133

6.3.3 Self-Scheduled Resources 133

6.3.4 Deviations from Day-ahead Market for Pool Scheduled Resources 133

6.3.5 Credits for Cancellation of Pool Scheduled Resources 134

6.3.6 Resource Specific Data Requirements 134

6.3.7 External Market Sellers 135

6.3.8 Day-ahead Market between 1200 and 1600 136

6.3.9 Rebidding Period between 1600 and 1800 136

6.3.10 Real Time Market 137

Section 7: External Transaction Scheduling 138

Section 8: Posting OASIS Information 139

Section 9: Hourly Scheduling 140

9.1 HOURLY SCHEDULING ADJUSTMENTS 140

Section 10: Overview of the Demand Resource Participation 142

10.1 OVERVIEW OF DEMAND RESOURCE PARTICIPATION 142

10.1.1 Economic Load Response Participant Review Process 143



10.2 DEMAND RESOURCE REGISTRATION REQUIREMENTS	144
10.2.1 Registration combinations.....	144
10.2.2 Curtailment Service Providers.....	145
10.2.3 PJM Activities	155
10.2.4 Electric Distribution Company (“EDC”) and Load Serving Entity (“LSE”) activities.....	156
10.2.5 CBL Certification Process.....	157
10.3 ECONOMIC ENERGY MARKET PARTICIPATION	158
10.3.1 Net Benefits Test to determine Net Benefits Threshold.....	163
10.4 DEMAND RESOURCE METERING AND SETTLEMENT DATA REQUIREMENTS	164
10.4.1 Metered Data.....	165
10.4.2 Customer Base Line (CBL).....	165
10.4.3 Economic Energy Settlements	175
10.4.3 Economic Energy Settlements Cost Allocation.....	177
10.5 AGGREGATION FOR ECONOMIC AND EMERGENCY DEMAND RESOURCES	179
10.5.1 Calculations for the weighted average line loss factor.....	180
10.5.2 Settlement for Aggregation.....	180
10.6 INTERVAL METER EQUIPMENT AND LOAD DATA REQUIREMENTS	181
10.7 USE OF SUB-METER LOAD DATA TO SUPPORT DEMAND RESPONSE REGULATION COMPLIANCE	183
Section 11: Overview of the Day-ahead Scheduling Reserve Market	185
11.1 OVERVIEW OF DAY-AHEAD SCHEDULING RESERVE MARKET	185
11.2 PJM DAY-AHEAD RESERVE MARKET BUSINESS RULES	185
11.2.1 Day-ahead Scheduling Reserve Market Reserve Requirement.....	185
11.2.2 Day-ahead Scheduling Reserve Market Eligibility.....	186
11.2.3 Day-ahead Scheduling Reserve Market Rules.....	187
11.2.4 Day-ahead Scheduling Reserve Market Offer Period	188
11.2.5 Day-ahead Scheduling Reserve Market Clearing.....	188
11.2.6 Day-ahead Scheduling Reserve Market Operations	190
11.2.7 Day-ahead Scheduling Reserve Performance	190



[11.2.8 Day-ahead Scheduling Reserve Market Obligation Fulfillment.....](#) 191

[11.2.9 Day-ahead Scheduling Reserve Bilateral Transactions.....](#) 191

[11.2.10 Day-ahead Scheduling Reserve Market Settlement.....](#) 192

[Attachment A: Interchange Energy Schedule Curtailment Order.....](#) 193

CURTAILMENT OF TRANSMISSION OR RECALL OF ENERGY: 193

[Non-Firm over Secondary Points not willing to pay congestion charges.....](#) 193

[Non-Firm not willing to pay congestion charges \(NF-NPC\).....](#) 193

[Network Import not willing to pay congestion charges \(Net-NPC\).....](#) 193

[Spot Market Import \(SPTIN\).....](#) 193

[Non-Firm over Secondary Points willing to pay congestion charges](#) 194

[Non-Firm willing to pay congestion charges \(NF-WPC\).....](#) 194

[Network Import willing to pay congestion charges \(Net-WPC\).....](#) 194

[Firm.....](#) 194

EXAMPLE OF RECALL OF ENERGY 194

[Firm.....](#) 195

[Curtailment of Capacity Backed Resources.....](#) 195

[Attachment B: Pumped Storage Modeling.....](#) 197

DESCRIPTION OF MODEL 197

[Attachment C: PJM Procedure for Cost Reimbursement.....](#) 199

[OFFERS 199](#)

[OPERATIONS 199](#)

[SETTLEMENTS 200](#)

[Revision History.....](#) 201

[Table of Contents.....](#) ii

[Table of Exhibits.....](#) vi



Approval.....7

Current Revision.....7

Introduction.....8

 ABOUT THIS MANUAL..... 8

Intended Audience.....9

References.....9

 USING THIS MANUAL..... 9

What You Will Find In This Manual.....10

Section 1: Overview of Energy & Ancillary Services Market Operations.....11

 1.1 PJM RESPONSIBILITIES..... 13

 1.2 PJM MARKET PARTICIPANTS RESPONSIBILITIES..... 14

 1.2.1 Market Buyers..... 14

 1.2.2 Market Sellers..... 15

 1.2.3 Load Serving Entities..... 16

 1.2.4 Curtailment Service Providers..... 16

Section 2: Overview of the PJM Energy Markets.....17

 2.1 OVERVIEW OF PJM ENERGY MARKETS..... 17

 2.2 DEFINITION OF LOCATIONAL MARGINAL PRICE..... 18

 2.3 ENERGY MARKET BUSINESS RULES..... 19

 2.3.1 Bidding & Operations Time Line..... 19

 2.3.2 Market Buyers..... 20

 2.3.3 Market Sellers..... 21

 2.3.4 Minimum Generator Operating Parameters – Parameter Limited Schedules..... 25

 2.3.5 Curtailment Service Providers..... 31



2.3.6 PJM Activities.....31

2.3.7 Mechanical/Technical Rules.....32

2.3.8 Modeling.....34

2.3.9 Day-ahead Locational Marginal Price (LMP) Calculations.....34

2.4 REAL-TIME LOCATIONAL MARGINAL PRICE (LMP) CALCULATIONS — 35

2.5 UNIT DISPATCH SYSTEM — 36

2.6 PJM STATE ESTIMATOR — 37

2.8 LOCATIONAL PRICING ALGORITHM — 40

2.9 PJM REAL-TIME LOCATIONAL MARGINAL PRICE VERIFICATION PROCEDURE — 43

2.10 PRICE BOUNDING VIOLATIONS — 44

2.11 CALCULATION OF RAMP LIMITED DESIRED MWH — 44

2.12 USING AND CALCULATING LOCATIONAL MARGINAL PRICES 46

2.12.1 Day-ahead Settlement.....47

2.12.2 Balancing Settlement.....47

2.13 BALANCING OPERATING RESERVE COST ANALYSIS 48

2.13.1 Maximum Emergency Generation in Day-ahead Market.....50

2.13.2 Minimum Capacity Emergency in Day-ahead Market.....51

Section 3: Overview of the PJM Regulation Market.....52

3.1 OVERVIEW OF THE PJM REGULATION MARKET — 52

3.2 PJM REGULATION MARKET BUSINESS RULES — 53

3.2.1 Regulation Market Eligibility.....53

3.2.2 Regulation Market Data Timeline.....54

3.2.3 Regulation Bilateral Transactions.....55

3.2.4 Regulation Requirement Determination.....56

3.2.5 Regulation Obligation Fulfillment.....56

3.2.6 Regulation Offer Period.....56

3.2.7 Regulation Market Clearing.....57



3.2.8 Hydro Units.....59

3.2.9 Regulation Market Operations.....60

3.2.10 Settlements.....61

Section 4: Overview of the PJM Synchronized Reserve Market.....62

4.1 OVERVIEW OF THE PJM SYNCHRONIZED RESERVE MARKET 62

4.2 PJM SYNCHRONIZED RESERVE MARKET BUSINESS RULES 63

4.2.1 Synchronized Reserve Market Eligibility.....63

4.2.3 Synchronized Reserve Requirement Determination.....65

4.2.4 Synchronized Reserve Obligation Fulfillment.....66

4.2.5 Synchronized Reserve Offer Period.....67

4.2.6 Bilateral Synchronized Reserve Transactions.....67

4.2.7 Synchronized Reserve Market Clearing.....68

4.2.8 Hydro Units.....70

4.2.9 Demand Resources.....71

4.2.10 Synchronized Reserve Market Operations.....71

4.2.11 Settlements.....72

4.2.12 Verification.....73

4.2.13 Non-Performance.....74

Section 5: Market Clearing Processes and Tools.....75

5.1 PJM PHILOSOPHY.....75

5.2 SCHEDULING TOOLS.....76

5.2.1 Enhanced Energy Scheduler (EES).....77

5.2.2 PJM eSchedules.....77

5.2.3 Load Forecasting.....77



5.2.4 Markets Database System.....78

5.2.5 Hydro Calculator.....82

5.2.6 PJM Energy Market Technical Software.....83

5.2.7 Synchronized Reserve and Regulation Scheduling Software (SPREGO).....86

Section 6: Reserve Requirements in PJM Energy Markets.....87

6.1 FORECASTING PJM GENERATION REQUIREMENT — 87

6.1.1 PJM Regulation Requirement.....89

6.1.2 Regulation Service.....91

6.2 PJM SYNCHRONIZED RESERVE REQUIREMENTS — 92

6.2.1 Synchronized Reserve Service.....93

6.3 PROCESSING MARKET INFORMATION — 94

6.3.1 PJM Member Load Forecasts.....94

6.3.2 Reserve Service.....94

6.3.3 Self-Scheduled Resources.....94

6.3.4 Deviations from Day-ahead Market for Pool Scheduled Resources.....95

6.3.5 Credits for Cancellation of Pool Scheduled Resources.....95

6.3.6 Resource Specific Data Requirements.....95

6.3.7 External Market Sellers.....96

6.3.8 Day-ahead Market between 1200 and 1600.....97

6.3.9 Rebidding Period between 1600 and 1800.....97

6.3.10 Real Time Market.....98

Section 7: External Transaction Scheduling.....99

Section 8: Posting OASIS Information.....100



Section 9: Hourly Scheduling..... 101

9.1 HOURLY SCHEDULING ADJUSTMENTS 101

Section 10: Overview of the Demand Resource Participation..... 102

10.1 OVERVIEW OF DEMAND RESOURCE PARTICIPATION 102

10.1.1 Economic Load Response Participant Review Process..... 103

10.2 DEMAND RESOURCE REGISTRATION REQUIREMENTS 103

10.2.1 Registrations combinations..... 104

10.2.2 Curtailment Service Providers..... 104

10.2.3 PJM Activities..... 110

10.2.4 Electric Distribution Company (“EDC”) and Load Serving Entity (“LSE”) activities..... 110

10.2.5 CBL Certification Process..... 110

10.3 ECONOMIC ENERGY MARKET PARTICIPATION 112

10.3.1 Net Benefits Test to determine Net Benefits Threshold..... 113

10.4 DEMAND RESOURCE METERING AND SETTLEMENT DATA REQUIREMENTS 114

10.4.1 Metered Data..... 115

10.4.2 Customer Base Line (CBL)..... 115

10.4.3 Economic Energy Settlements..... 121

10.4.3 Economic Energy Settlements Cost Allocation..... 122

10.5 AGGREGATION FOR ECONOMIC AND EMERGENCY DEMAND RESOURCES 122

10.5.1 Calculations for the weighted average line loss factor..... 123

10.5.2 Settlement for Aggregation..... 123

10.6 INTERVAL METER EQUIPMENT AND LOAD DATA REQUIREMENTS 124

10.7 USE OF SUB-METER LOAD DATA TO SUPPORT DEMAND RESPONSE REGULATION COMPLIANCE 125

Section 11: Overview of the Day-ahead Scheduling Reserve Market..... 128



11.1 OVERVIEW OF DAY-AHEAD SCHEDULING RESERVE MARKET..... 128

11.2 PJM DAY-AHEAD RESERVE MARKET BUSINESS RULES..... 128

11.2.1 Day-ahead Scheduling Reserve Market Reserve Requirement..... 128

11.2.2 Day-ahead Scheduling Reserve Market Eligibility..... 129

11.2.3 Day-ahead Scheduling Reserve Market Rules..... 130

11.2.4 Day-ahead Scheduling Reserve Market Offer Period..... 131

11.2.5 Day-ahead Scheduling Reserve Market Clearing..... 131

11.2.6 Day-ahead Scheduling Reserve Market Operations..... 132

11.2.7 Day-ahead Scheduling Reserve Performance..... 132

11.2.8 Day-ahead Scheduling Reserve Market Obligation Fulfillment..... 133

11.2.9 Day-ahead Scheduling Reserve Bilateral Transactions..... 134

11.2.10 Day-ahead Scheduling Reserve Market Settlement..... 134

Attachment A: Interchange Energy Schedule Curtailment Order..... 136

CURTAILMENT OF TRANSMISSION OR RECALL OF ENERGY:..... 136

Non-Firm over Secondary Points not willing to pay congestion charges..... 136

Non-Firm not willing to pay congestion charges (NF-NPC)..... 136

Network Import not willing to pay congestion charges (Net-NPC)..... 136

Spot Market Import (SPTIN)..... 136

Non-Firm over Secondary Points willing to pay congestion charges..... 137

Non-Firm willing to pay congestion charges (NF-WPC)..... 137

Network Import willing to pay congestion charges (Net-WPC)..... 137

Firm..... 137

EXAMPLE OF RECALL OF ENERGY 137

Firm..... 137



Curtailment of Capacity Backed Resources.....138

Attachment B: Pumped Storage Modeling.....139

 DESCRIPTION OF MODEL.....139

Attachment C: PJM Procedure for Cost Reimbursement.....141

 OFFERS.....141

 OPERATIONS.....141

 SETTLEMENTS.....141

Revision History.....143

Table of Contents.....iii

Table of Exhibits.....vi

Approval.....7

Current Revision.....7

Introduction.....8

 — ABOUT THIS MANUAL 8

Intended Audience.....9

References.....9

 USING THIS MANUAL.....9

What You Will Find In This Manual.....10

Section 1: Overview of Energy & Ancillary Services Market Operations.....11

 1.1 PJM RESPONSIBILITIES.....13

 1.2 PJM MARKET PARTICIPANTS RESPONSIBILITIES.....14

 1.2.1 Market Buyers.....14

 1.2.2 Market Sellers.....15

 1.2.3 Load Serving Entities.....16

Formatted: TOC 2,PJM_TOC 2, No bullets or numbering



[1.2.4 Curtailment Service Providers](#).....16

[Section 2: Overview of the PJM Energy Markets](#).....17

[2.1 OVERVIEW OF PJM ENERGY MARKETS](#).....17

[2.2 DEFINITION OF LOCATIONAL MARGINAL PRICE](#).....18

[2.3 ENERGY MARKET BUSINESS RULES](#).....19

[2.3.1 Bidding & Operations Time Line](#).....19

[2.3.2 Market Buyers](#).....20

[2.3.3 Market Sellers](#).....21

[2.3.4 Minimum Generator Operating Parameters – Parameter Limited Schedules](#).....25

[2.3.5 Curtailment Service Providers](#).....31

[2.3.6 PJM Activities](#).....31

[2.3.7 Mechanical/Technical Rules](#).....32

[2.3.8 Modeling](#).....34

[2.3.9 Day-ahead Locational Marginal Price \(LMP\) Calculations](#).....34

[2.4 REAL-TIME LOCATIONAL MARGINAL PRICE \(LMP\) CALCULATIONS](#).....35

[2.5 UNIT DISPATCH SYSTEM](#).....36

[2.6 PJM STATE ESTIMATOR](#).....37

[2.8 LOCATIONAL PRICING ALGORITHM](#).....41

[2.9 PJM REAL-TIME LOCATIONAL MARGINAL PRICE VERIFICATION PROCEDURE](#).....44

[2.10 PRICE-BOUNDING VIOLATIONS](#).....45

[2.11 CALCULATION OF RAMP LIMITED DESIRED MWH](#).....45

[2.12 USING AND CALCULATING LOCATIONAL MARGINAL PRICES](#).....47

[2.12.1 Day-ahead Settlement](#).....48

[2.12.2 Balancing Settlement](#).....49

[2.13 BALANCING OPERATING RESERVE COST ANALYSIS](#).....49

[2.13.1 Maximum Emergency Generation in Day-ahead Market](#).....51

[2.13.2 Minimum Capacity Emergency in Day-ahead Market](#).....52



Section 3: Overview of the PJM Regulation Market53

3.1 OVERVIEW OF THE PJM REGULATION MARKET 53

3.2 PJM REGULATION MARKET BUSINESS RULES 54

3.2.1 Regulation Market Eligibility..... 54

3.2.2 Regulation Market Data Timeline..... 55

3.2.3 Regulation Bilateral Transactions..... 56

3.2.4 Regulation Requirement Determination..... 57

3.2.5 Regulation Obligation Fulfillment..... 57

3.2.6 Regulation Offer Period..... 57

3.2.7 Regulation Market Clearing..... 58

3.2.8 Hydro Units..... 60

3.2.9 Regulation Market Operations..... 61

3.2.10 Settlements..... 62

Section 4: Overview of the PJM Synchronized Reserve Market63

4.1 OVERVIEW OF THE PJM SYNCHRONIZED RESERVE MARKET 63

4.2 PJM SYNCHRONIZED RESERVE MARKET BUSINESS RULES 64

4.2.1 Synchronized Reserve Market Eligibility..... 64

4.2.3 Synchronized Reserve Requirement Determination..... 66

4.2.4 Synchronized Reserve Obligation Fulfillment..... 67

4.2.5 Synchronized Reserve Offer Period..... 68

4.2.6 Bilateral Synchronized Reserve Transactions..... 68

4.2.7 Synchronized Reserve Market Clearing..... 69

4.2.8 Hydro Units..... 71

4.2.9 Demand Resources..... 72



4.2.10 Synchronized Reserve Market Operations.....72

4.2.11 Settlements.....73

4.2.12 Verification.....74

4.2.13 Non-Performance.....75

Section 5: Market Clearing Processes and Tools.....76

5.1 PJM PHILOSOPHY.....76

5.2 SCHEDULING TOOLS.....77

5.2.1 Enhanced Energy Scheduler (EES).....78

5.2.2 PJM eSchedules.....78

5.2.3 Load Forecasting.....78

5.2.4 Markets Database System.....79

5.2.5 Hydro Calculator.....83

5.2.6 PJM Energy Market Technical Software.....84

5.2.7 Synchronized Reserve and Regulation Scheduling Software (SPREGO).....87

Section 6: Reserve Requirements in PJM Energy Markets.....88

6.1 FORECASTING PJM GENERATION REQUIREMENT.....88

6.1.1 PJM Regulation Requirement.....90

6.1.2 Regulation Service.....92

6.2 PJM SYNCHRONIZED RESERVE REQUIREMENTS.....93

6.2.1 Synchronized Reserve Service.....94

6.3 PROCESSING MARKET INFORMATION.....95

6.3.1 PJM Member Load Forecasts.....95

6.3.2 Reserve Service.....95

6.3.3 Self-Scheduled Resources.....95



6.3.4 Deviations from Day-ahead Market for Pool Scheduled Resources.....96

6.3.5 Credits for Cancellation of Pool Scheduled Resources.....96

6.3.6 Resource Specific Data Requirements.....96

6.3.7 External Market Sellers.....97

6.3.8 Day-ahead Market between 1200 and 1600.....98

6.3.9 Rebidding Period between 1600 and 1800.....98

6.3.10 Real Time Market.....99

Section 7: External Transaction Scheduling.....100

Section 8: Posting OASIS Information.....101

Section 9: Hourly Scheduling.....102

9.1 HOURLY SCHEDULING ADJUSTMENTS 102

Section 10: Overview of the Demand Resource Participation.....103

10.1 OVERVIEW OF DEMAND RESOURCE PARTICIPATION 103

10.1.1 Economic Load Response Participant Review Process.....104

10.2 DEMAND RESOURCE REGISTRATION REQUIREMENTS 104

10.2.1 Curtailment Service Providers.....105

10.2.2 PJM Activities.....110

10.2.3 Electric Distribution Company (“EDC”) and Load Serving Entity (“LSE”) activities.....110

10.2.4 CBL Certification Process.....110

10.3 ECONOMIC ENERGY MARKET PARTICIPATION 112

10.3.1 Net Benefits Test to determine Net Benefits Threshold.....113

10.4 DEMAND RESOURCE METERING AND SETTLEMENT DATA REQUIREMENTS 115

10.4.1 Metered Data.....115



[10.4.2 Customer Base Line \(CBL\).....116](#)

[10.4.3 Economic Energy Settlements122](#)

[10.4.3 Economic Energy Settlements Cost Allocation.....123](#)

[10.5 AGGREGATION FOR ECONOMIC AND EMERGENCY DEMAND RESOURCES — 123](#)

[10.5.1 Calculations for the weighted average line loss factor124](#)

[10.5.2 Settlement for Aggregation.....124](#)

[10.6 INTERVAL METER EQUIPMENT AND LOAD DATA REQUIREMENTS — 125](#)

[Section 11: Overview of the Day-ahead Scheduling Reserve Market.....127](#)

[11.1 OVERVIEW OF DAY-AHEAD SCHEDULING RESERVE MARKET — 127](#)

[11.2 PJM DAY-AHEAD RESERVE MARKET BUSINESS RULES — 127](#)

[11.2.1 Day-ahead Scheduling Reserve Market Reserve Requirement.....127](#)

[11.2.2 Day-ahead Scheduling Reserve Market Eligibility.....128](#)

[11.2.3 Day-ahead Scheduling Reserve Market Rules.....129](#)

[11.2.4 Day-ahead Scheduling Reserve Market Offer Period.....130](#)

[11.2.5 Day-ahead Scheduling Reserve Market Clearing.....130](#)

[11.2.6 Day-ahead Scheduling Reserve Market Operations.....131](#)

[11.2.7 Day-ahead Scheduling Reserve Performance.....131](#)

[11.2.8 Day-ahead Scheduling Reserve Market Obligation Fulfillment.....132](#)

[11.2.9 Day-ahead Scheduling Reserve Bilateral Transactions.....133](#)

[11.2.10 Day-ahead Scheduling Reserve Market Settlement.....133](#)

[Attachment A: Interchange Energy Schedule Curtailment Order.....135](#)

[CURTAILMENT OF TRANSMISSION OR RECALL OF ENERGY: — 135](#)

[Non-Firm over Secondary Points not willing to pay congestion charges.....135](#)

[Non-Firm not willing to pay congestion charges \(NF-NPC\).....135](#)



Network Import not willing to pay congestion charges (Net-NPC).....135

Spot Market Import (SPTIN).....135

Non-Firm over Secondary Points willing to pay congestion charges.....136

Non-Firm willing to pay congestion charges (NF-WPC).....136

Network Import willing to pay congestion charges (Net-WPC).....136

Firm.....136

EXAMPLE OF RECALL OF ENERGY 136

Firm.....136

Curtailment of Capacity Backed Resources.....137

Attachment B: Pumped Storage Modeling.....138

DESCRIPTION OF MODEL—138

Attachment C: PJM Procedure for Cost Reimbursement.....140

OFFERS—140

OPERATIONS—140

SETTLEMENTS—140

Revision History.....142

Table of Contents.....ii

Table of Exhibits.....vi

Approval.....7

Current Revision.....7

Introduction.....8

ABOUT THIS MANUAL—8

Intended Audience.....9



References.....9

USING THIS MANUAL.....9

What You Will Find In This Manual.....10

Section 1: Overview of Energy & Ancillary Services Market Operations11

1.1 PJM RESPONSIBILITIES.....13

1.2 PJM MARKET PARTICIPANTS RESPONSIBILITIES.....14

1.2.1 Market Buyers.....14

1.2.2 Market Sellers.....15

1.2.3 Load Serving Entities.....16

1.2.4 Curtailment Service Providers.....16

Section 2: Overview of the PJM Energy Markets17

2.1 OVERVIEW OF PJM ENERGY MARKETS.....17

2.2 DEFINITION OF LOCATIONAL MARGINAL PRICE.....18

2.3 ENERGY MARKET BUSINESS RULES.....19

2.3.1 Bidding & Operations Time Line:.....19

2.3.2 Market Buyers.....20

2.3.3 Market Sellers.....21

2.3.4 Minimum Generator Operating Parameters — Parameter Limited Schedules.....25

2.3.5 Curtailment Service Providers.....31

2.3.6 PJM Activities.....31

2.3.7 Mechanical/Technical Rules.....32

2.3.8 Modeling.....34

2.3.9 Day-ahead Locational Marginal Price (LMP) Calculations.....34

2.4 REAL-TIME LOCATIONAL MARGINAL PRICE (LMP) CALCULATIONS.....35



2.5 UNIT DISPATCH SYSTEM 36

2.6 PJM STATE ESTIMATOR 37

2.8 LOCATIONAL PRICING ALGORITHM 41

2.9 PJM REAL TIME LOCATIONAL MARGINAL PRICE VERIFICATION PROCEDURE 44

2.10 PRICE BOUNDING VIOLATIONS 45

2.11 CALCULATION OF RAMP LIMITED DESIRED MWH 45

2.12 USING AND CALCULATING LOCATIONAL MARGINAL PRICES 47

2.12.1 Day-ahead Settlement..... 48

2.12.2 Balancing Settlement..... 49

2.13 BALANCING OPERATING RESERVE COST ANALYSIS 49

2.13.1 Maximum Emergency Generation in Day-ahead Market..... 51

2.13.2 Minimum Capacity Emergency in Day-ahead Market..... 52

Section 3: Overview of the PJM Regulation Market..... 53

3.1 OVERVIEW OF THE PJM REGULATION MARKET 53

3.2 PJM REGULATION MARKET BUSINESS RULES 54

3.2.1 Regulation Market Eligibility..... 54

3.2.2 Regulation Market Data Timeline..... 55

3.2.3 Regulation Bilateral Transactions..... 56

3.2.4 Regulation Requirement Determination..... 57

3.2.5 Regulation Obligation Fulfillment..... 57

3.2.6 Regulation Offer Period..... 57

3.2.7 Regulation Market Clearing..... 58

3.2.8 Hydro Units..... 60

3.2.9 Regulation Market Operations..... 61

3.2.10 Settlements..... 62

Section 4: Overview of the PJM Synchronized Reserve Market..... 63



4.1 OVERVIEW OF THE PJM SYNCHRONIZED RESERVE MARKET 63

4.2 PJM SYNCHRONIZED RESERVE MARKET BUSINESS RULES 64

4.2.1 Synchronized Reserve Market Eligibility.....64

4.2.3 Synchronized Reserve Requirement Determination.....66

4.2.4 Synchronized Reserve Obligation Fulfillment.....67

4.2.5 Synchronized Reserve Offer Period.....68

4.2.6 Bilateral Synchronized Reserve Transactions.....68

4.2.7 Synchronized Reserve Market Clearing.....69

4.2.8 Hydro Units.....71

4.2.9 Demand Resources.....72

4.2.10 Synchronized Reserve Market Operations.....72

4.2.11 Settlements.....73

4.2.12 Verification.....74

4.2.13 Non-Performance.....75

Section 5: Market Clearing Processes and Tools.....76

5.1 PJM PHILOSOPHY.....76

5.2 SCHEDULING TOOLS.....77

5.2.1 Enhanced Energy Scheduler (EES).....78

5.2.2 PJM eSchedules.....78

5.2.3 Load Forecasting.....78

5.2.4 Markets Database System.....79

5.2.5 Hydro Calculator.....83

5.2.6 PJM Energy Market Technical Software.....84

5.2.7 Synchronized Reserve and Regulation Scheduling Software (SPREGO).....87



Section 6: Reserve Requirements in PJM Energy Markets.....88

6.1 FORECASTING PJM GENERATION REQUIREMENT — 88

6.1.1 PJM Regulation Requirement.....90

6.1.2 Regulation Service.....92

6.2 PJM SYNCHRONIZED RESERVE REQUIREMENTS — 93

6.2.1 Synchronized Reserve Service.....94

6.3 PROCESSING MARKET INFORMATION 95

6.3.1 PJM Member Load Forecasts.....95

6.3.2 Reserve Service.....95

6.3.3 Self-Scheduled Resources.....95

6.3.4 Deviations from Day-ahead Market for Pool Scheduled Resources.....96

6.3.5 Credits for Cancellation of Pool Scheduled Resources.....96

6.3.6 Resource Specific Data Requirements.....96

6.3.7 External Market Sellers.....97

6.3.8 Day-ahead Market between 1200 and 1600.....98

6.3.9 Rebidding Period between 1600 and 1800.....98

6.3.10 Real Time Market.....99

Section 7: External Transaction Scheduling.....100

Section 8: Posting OASIS Information.....101

Section 9: Hourly Scheduling.....102

9.1 HOURLY SCHEDULING ADJUSTMENTS 102

Section 10: Overview of the Demand Resource Participation.....103

10.1 OVERVIEW OF DEMAND RESOURCE PARTICIPATION — 103

10.1.1 Economic Load Response Participant Review Process.....104



10.2 DEMAND RESOURCE REGISTRATION REQUIREMENTS — 104

10.2.1 Curtailment Service Providers..... 105

10.2.2 PJM Activities..... 110

10.2.3 Electric Distribution Company (“EDC”) and Load Serving Entity (“LSE”) activities..... 110

10.2.4 CBL Certification Process..... 110

10.3 ECONOMIC ENERGY MARKET PARTICIPATION — 112

NET BENEFITS TEST TO DETERMINE NET BENEFITS THRESHOLD 113

10.4 DEMAND RESOURCE METERING AND SETTLEMENT DATA REQUIREMENTS 115

10.4.1 Metered Data..... 115

10.4.2 Customer Base Line (CBL)..... 116

10.4.3 Economic Energy Settlements..... 122

10.4.3 Economic Energy Settlements Cost Allocation..... 123

10.5 AGGREGATION FOR ECONOMIC AND EMERGENCY DEMAND RESOURCES — 123

10.5.1 Calculations for the weighted average line loss factor..... 124

10.5.2 Settlement for Aggregation..... 124

10.6 INTERVAL METER EQUIPMENT AND LOAD DATA REQUIREMENTS — 125

Section 11: Overview of the Day-ahead Scheduling Reserve Market..... 127

11.1 OVERVIEW OF DAY-AHEAD SCHEDULING RESERVE MARKET — 127

11.2 PJM DAY-AHEAD RESERVE MARKET BUSINESS RULES — 127

11.2.1 Day-ahead Scheduling Reserve Market Reserve Requirement..... 127

11.2.2 Day ahead Scheduling Reserve Market Eligibility..... 128

11.2.3 Day-ahead Scheduling Reserve Market Rules..... 129

11.2.4 Day-ahead Scheduling Reserve Market Offer Period..... 130

11.2.5 Day-ahead Scheduling Reserve Market Clearing..... 130

11.2.6 Day ahead Scheduling Reserve Market Operations..... 131



11.2.7 Day-ahead Scheduling Reserve Performance.....131

11.2.8 Day-ahead Scheduling Reserve Market Obligation Fulfillment.....132

11.2.9 Day-ahead Scheduling Reserve Bilateral Transactions.....133

11.2.10 Day-ahead Scheduling Reserve Market Settlement.....133

Attachment A: Interchange Energy Schedule Curtailment Order.....135

CURTAILMENT OF TRANSMISSION OR RECALL OF ENERGY:.....135

Non-Firm over Secondary Points not willing to pay congestion charges.....135

Non-Firm not willing to pay congestion charges (NF-NPC).....135

Network Import not willing to pay congestion charges (Not-NPC).....135

Spot Market Import (SPTIN).....135

Non-Firm over Secondary Points willing to pay congestion charges.....136

Non-Firm willing to pay congestion charges (NF-WPC).....136

Network Import willing to pay congestion charges (Not-WPC).....136

Firm.....136

EXAMPLE OF RECALL OF ENERGY.....136

Firm.....136

Curtailment of Capacity Backed Resources.....137

Attachment B: Pumped Storage Modeling.....138

DESCRIPTION OF MODEL.....138

Attachment C: PJM Procedure for Cost Reimbursement.....140

OFFERS.....140

OPERATIONS.....140

SETTLEMENTS.....140

Revision History.....142



Table of Contents.....ii

Table of Exhibits.....vi

Approval.....7

Current Revision.....7

Introduction.....8

ABOUT THIS MANUAL.....8

Intended Audience.....9

References.....9

USING THIS MANUAL.....9

What You Will Find In This Manual.....10

Section 1: Overview of Energy & Ancillary Services Market Operations.....11

1.1 PJM RESPONSIBILITIES.....13

1.2 PJM MARKET PARTICIPANTS RESPONSIBILITIES.....14

1.2.1 Market Buyers.....14

1.2.2 Market Sellers.....15

1.2.3 Load Serving Entities.....16

1.2.4 Curtailment Service Providers.....16

Section 2: Overview of the PJM Energy Markets.....17

2.1 OVERVIEW OF PJM ENERGY MARKETS.....17

2.2 DEFINITION OF LOCATIONAL MARGINAL PRICE.....18

2.3 ENERGY MARKET BUSINESS RULES.....19

2.3.1 Bidding & Operations Time Line.....19

2.3.2 Market Buyers.....20

2.3.3 Market Sellers.....21



2.3.4 Minimum Generator Operating Parameters – Parameter Limited Schedules.....2526

2.3.5 Curtailment Service Providers.....31

2.3.6 PJM Activities.....31

2.3.7 Mechanical/Technical Rules.....33

2.3.8 Modeling.....34

2.3.9 Day-ahead Locational Marginal Price (LMP) Calculations.....3435

2.4 REAL-TIME LOCATIONAL MARGINAL PRICE (LMP) CALCULATIONS — 35

2.5 UNIT DISPATCH SYSTEM — 36

2.6 PJM STATE ESTIMATOR — 37

2.8 LOCATIONAL PRICING ALGORITHM — 41

2.9 PJM REAL-TIME LOCATIONAL MARGINAL PRICE VERIFICATION PROCEDURE — 44

2.10 PRICE-BOUNDING VIOLATIONS — 45

2.11 CALCULATION OF RAMP LIMITED DESIRED MWH — 45

2.12 USING AND CALCULATING LOCATIONAL MARGINAL PRICES 47

2.12.1 Day-ahead Settlement.....48

2.12.2 Balancing Settlement.....49

2.13 BALANCING OPERATING RESERVE COST ANALYSIS 49

2.13.1 Maximum Emergency Generation in Day-ahead Market.....51

2.13.2 Minimum Capacity Emergency in Day-ahead Market.....52

Section 3: Overview of the PJM Regulation Market.....53

3.1 OVERVIEW OF THE PJM REGULATION MARKET — 53

3.2 PJM REGULATION MARKET BUSINESS RULES — 54

3.2.1 Regulation Market Eligibility.....54

3.2.2 Regulation Market Data Timeline.....55

3.2.3 Regulation Bilateral Transactions.....56

3.2.4 Regulation Requirement Determination.....57



3.2.5 Regulation Obligation Fulfillment.....57

3.2.6 Regulation Offer Period.....57

3.2.7 Regulation Market Clearing.....58

3.2.8 Hydro Units.....60

3.2.9 Regulation Market Operations.....61

3.2.10 Settlements.....62

Section 4: Overview of the PJM Synchronized Reserve Market.....63

4.1 OVERVIEW OF THE PJM SYNCHRONIZED RESERVE MARKET63

4.2 PJM SYNCHRONIZED RESERVE MARKET BUSINESS RULES 64

4.2.1 Synchronized Reserve Market Eligibility.....64

4.2.3 Synchronized Reserve Requirement Determination.....66

4.2.4 Synchronized Reserve Obligation Fulfillment.....67

4.2.5 Synchronized Reserve Offer Period.....68

4.2.6 Bilateral Synchronized Reserve Transactions.....68

4.2.7 Synchronized Reserve Market Clearing.....69

4.2.8 Hydro Units.....71

4.2.9 Demand Resources.....72

4.2.10 Synchronized Reserve Market Operations.....73

4.2.11 Settlements.....73

4.2.12 Verification.....74

4.2.13 Non-Performance.....75

Section 5: Market Clearing Processes and Tools.....76

5.1 PJM PHILOSOPHY——76



5.2 SCHEDULING TOOLS — 77

- 5.2.1 Enhanced Energy Scheduler (EES).....78**
- 5.2.2 PJM eSchedules.....78**
- 5.2.3 Load Forecasting.....78**
- 5.2.4 Markets Database System.....79**
- 5.2.5 Hydro Calculator.....83**
- 5.2.6 PJM Energy Market Technical Software.....84**
- 5.2.7 Synchronized Reserve and Regulation Scheduling Software (SPREGO).....87**

Section 6: Reserve Requirements in PJM Energy Markets.....88

6.1 FORECASTING PJM GENERATION REQUIREMENT — 88

- 6.1.1 PJM Regulation Requirement.....90**
- 6.1.2 Regulation Service.....92**

6.2 PJM SYNCHRONIZED RESERVE REQUIREMENTS — 93

- 6.2.1 Synchronized Reserve Service.....94**

6.3 PROCESSING MARKET INFORMATION — 95

- 6.3.1 PJM Member Load Forecasts.....95**
- 6.3.2 Reserve Service.....95**
- 6.3.3 Self-Scheduled Resources.....95**
- 6.3.4 Deviations from Day-ahead Market for Pool Scheduled Resources.....96**
- 6.3.5 Credits for Cancellation of Pool Scheduled Resources.....96**
- 6.3.6 Resource Specific Data Requirements.....96**
- 6.3.7 External Market Sellers.....97**
- 6.3.8 Day-ahead Market between 1200 and 1600.....98**
- 6.3.9 Rebidding Period between 1600 and 1800.....98**



6.3.10 Real Time Market.....99

Section 7: External Transaction Scheduling.....100

Section 8: Posting OASIS Information.....101

Section 9: Hourly Scheduling.....102

9.1 HOURLY SCHEDULING ADJUSTMENTS 102

Section 10: Overview of the Demand Resource Participation.....103

10.1 OVERVIEW OF DEMAND RESOURCE PARTICIPATION 103

10.1.1 Economic Load Response Participant Review Process.....104

10.2 DEMAND RESOURCE REGISTRATION REQUIREMENTS 104

10.2.1 Curtailment Service Providers.....105

10.2.2 PJM Activities.....111109

10.2.3 Process for Determining the Appropriate CBL (standard or alternative)
.....112110

10.3 ECONOMIC ENERGY MARKET PARTICIPATION 120110

10.3.1 Day-ahead Operations.....122110

10.3.2 Real-time Operations.....123112

10.4 DEMAND RESOURCE METERING AND SETTLEMENT DATA REQUIREMENTS125113

10.4.1 Metered Data.....125113

10.4.2 Customer Baseline Load (CBL).....126114

10.4.3 Settlements Data Requirements.....134116

10.5 AGGREGATION FOR ECONOMIC LOAD RESPONSE—136117

10.5.1 Calculations for the weighted average retail rate and line loss factor137118

10.5.2 Settlement for Aggregation.....138118

10.6 INTERVAL METER EQUIPMENT AND LOAD DATA REQUIREMENTS—138119

Section 11: Overview of the Day-ahead Scheduling Reserve Market.....141121

Formatted: TOC 2,PJM_TOC 2



11.1 OVERVIEW OF DAY-AHEAD SCHEDULING RESERVE MARKET 141121

11.2 PJM DAY-AHEAD RESERVE MARKET BUSINESS RULES 141121

11.2.1 Day-ahead Scheduling Reserve Market Reserve Requirement 141121

11.2.2 Day-ahead Scheduling Reserve Market Eligibility 142122

11.2.3 Day-ahead Scheduling Reserve Market Rules 143123

11.2.4 Day-ahead Scheduling Reserve Market Offer Period 144124

11.2.5 Day-ahead Scheduling Reserve Market Clearing 144124

11.2.6 Day-ahead Scheduling Reserve Market Operations 145125

11.2.7 Day-ahead Scheduling Reserve Performance 145125

11.2.8 Day-ahead Scheduling Reserve Market Obligation Fulfillment 146126

11.2.9 Day-ahead Scheduling Reserve Bilateral Transactions 147127

11.2.10 Day-ahead Scheduling Reserve Market Settlement 148128

Attachment A: Interchange Energy Schedule Curtailment Order 149129

CURTAILMENT OF TRANSMISSION OR RECALL OF ENERGY: 149129

Non-Firm over Secondary Points not willing to pay congestion charges 149129

Non-Firm not willing to pay congestion charges (NF-NPC) 149129

Network Import not willing to pay congestion charges (Net-NPC) 149129

Spot Market Import (SPTIN) 149129

Non-Firm over Secondary Points willing to pay congestion charges 150130

Non-Firm willing to pay congestion charges (NF-WPC) 150130

Network Import willing to pay congestion charges (Net-WPC) 150130

Firm 150130

EXAMPLE OF RECALL OF ENERGY 150130

Firm 150130



Curtailment of Capacity Backed Resources.....151131

Attachment B: Pumped Storage Modeling.....**152132**

DESCRIPTION OF MODEL.....152132

Attachment C: PJM Procedure for Cost Reimbursement.....**154134**

OFFERS.....154134

OPERATIONS.....154134

SETTLEMENTS.....154134

Revision History.....**156136**



Table of Exhibits

EXHIBIT 1: SCHEDULING TIMELINE	43
EXHIBIT 2: LOAD FORECASTING PROCESS	114
EXHIBIT 3: SYNCHRONIZED RESERVE AND REGULATION MARKET DAILY TIMELINE	116
EXHIBIT 4: SYNCHRONIZED RESERVE AND REGULATION MARKET HOURLY TIMELINE	117
EXHIBIT 5: SETTLEMENT SUBSYSTEMS	120
EXHIBIT 6: DOWNLOAD DATA FROM MARKETS DATABASE	121
EXHIBIT 7: ENERGY MARKET DATA FLOW	122
EXHIBIT 8: SYNCHRONIZED RESERVE AND REGULATION SUBSYSTEMS	123
EXHIBIT 9: REQUIREMENT VERSUS RESOURCE SUPPLY	125
EXHIBIT 10: SYNCHRONIZED & REGULATION DATA FLOW	128
EXHIBIT 11: GENERATOR REGULATION SERVICE	131
EXHIBIT 12: CAPACITY AND ENERGY RESOURCE DATA REQUIREMENTS	135

Formatted: Table of Figures



Approval

Approval Date: 04/03/2012

Effective Date: 04/03/2012

Mike Ward, Manager

Day-ahead Market Operations

Rebecca Carroll, Manager

Real-time Market Operations

Formatted: PJM_Normal_Indented_1

Current Revision

Revision 51 (MM/dd/yyyy)

Conforming changes to section 10 (demand response participation) based on order 745 (ER11-4106-000). Changes include DR compensation, cost allocation, CBL and associated approval process, elimination of self scheduling, implementation of dispatch group. Conforming changes to section 10 based on elimination of compensation based on LMP-G&T under NBT (ER12-1705-000). Conforming changes to section 10 based regulation market changes (ER12-1430) for demand response (Economic Regulation Only registration and ability to use additional CSP, modified aggregation rules for Economic Regulation Only registration and use of submeter load data to determine regulation performance. This change also included miscellaneous clean up and reformatting for section 10.

Revisions 50 (04/03/2012):

— Add bullet to Section 2.3.3 pointing to Manual M-28 regarding make whole provisions for generators committed in the Day-ahead Market and not run in real-time.

Republished 04/12/2012 to remove an erroneous bullet point that had stated: "A Generator that has been notified of a restriction due to a projected reliability condition, should not submit an



~~economic maximum or maximum emergency bid into the Day Ahead market higher than the communicated restriction. A forced outage ticket should be entered into eDART (Outside Management Control) for the duration of the restriction."~~



Introduction

Welcome to the ***PJM Manual for Energy & Ancillary Services Market Operations***. In this Introduction, you will find the following information:

- What you can expect from the PJM Manuals in general (see “*About PJM Manuals*”).
- What you can expect from this PJM Manual (see “*About This Manual*”).
- How to use this manual (see “*Using This Manual*”).

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- Generation and transmission interconnection
- Reserve
- Accounting and Billing
- PJM administrative services

For a complete list of all PJM Manuals, go to www.pjm.com and select “Manuals” under the “Documents” tab.

About This Manual

The ***PJM Manual for Energy & Ancillary Services Market Operations*** is one of a series of manuals within the PJM Energy Market manuals. This manual focuses on the day-ahead and hourly scheduling activities that are performed by the PJM staff and the PJM Members. The manual describes the rules and procedures that are followed to schedule resources.

The ***PJM Manual for Energy & Ancillary Services Market Operations*** consists of ten sections. The sections are listed in the table of contents beginning on page ii.



Intended Audience

The intended audience of *the PJM Manual for Energy & Ancillary Services Market Operations* is:

- *PJM Members* - Any participants requesting to purchase or sell energy to or from the PJM Interchange Energy Market and any participant that schedules bilateral sales or purchases.
- *PJM operations staff* - The PJM operations staff processes the market information and develops the resource schedule.
- *PJM dispatchers* - The PJM dispatchers process PJM Member requests, make hourly schedule adjustments, and post information in the OASIS.
- *Local Control Center dispatchers* - The Local Control Center dispatchers submit hourly schedule changes.
- *Local Control Center operations support staff* - The Local Control Center operations support staff support the day-ahead information requirements.

References

The References to other documents that provide background or additional detail directly related to the *PJM Manual for Energy & Ancillary Services Market Operations* are:

- EES User's Guide
- PJM Manual for [Transmission Operations\(M-03\)](#)
- PJM Manual for [PJM OASIS Operation \(M-04\)](#)
- PJM Manual for [PJM eSchedules \(M-09\)](#)
- PJM Manual for [Pre-Scheduling Operations \(M-10\)](#)
- PJM Manual for [Balancing Operations \(M-12\)](#)
- PJM Manual for [Operating Agreement Accounting \(M-28\)](#)
- PJM Manual for [Definitions & Abbreviations \(M-35\)](#)



Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section with an overview. Then, we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manual's structure.

What You Will Find In This Manual

- A table of contents that lists two levels of subheadings within each of the sections
- An approval page that lists the required approvals and a brief outline of the current revision
- Sections containing the specific guidelines, requirements, or procedures including PJM actions and market participant actions
- Attachments that include additional supporting documents, forms, or tables in this PJM Manual
- A section at the end detailing all previous revisions of the PJM Manual
- A new introduction with the "List of PJM Manuals" table removed.



Section 1: Overview of Energy & Ancillary Services Market Operations

Welcome to the *Overview of Energy & Ancillary Services Market Operations* of the *PJM Manual for Energy & Ancillary Services Market Operations*. In this section you will find the following information:

- A description of the scope and purpose of scheduling (see “*Scope & Purpose of Energy & Ancillary Services Market Operations*”).
- A list of the PJM responsibilities (see “*PJM Responsibilities*”).
- A list of the market participants’ scheduling responsibilities (see “*PJM Market Participant Responsibilities*”).

Scope & Purpose of Energy & Ancillary Services Market Operations

Operation of the PJM RTO markets involves many activities that are performed by different operating and technical personnel. These activities occur in parallel on a continuous basis, 24 hours a day and can be grouped into three overlapping time frames:

- pre-scheduling operations
- scheduling operations and the Day-ahead Energy Market
- dispatching and the Real-time Energy Market

In the *PJM Manual for Energy & Ancillary Services Market* we focus mainly on the activities that take place one day prior to the Operating Day including the activities associated with the Day-ahead Energy Market. Exhibit 2 presents the scheduling activities in the form of a time line. The reference point for the timeline is the “Operating Day”, recognizing that every new day becomes an Operating Day. This timeline-type of description is used throughout this PJM Manual.

Generation resources, regardless of fuel type, fall into one of two categories, Capacity Resources or Energy Resources. If available, All Generation Capacity Resources, that have an RPM Resource Commitment must submit offer data into the Day-ahead Market and may elect either to Self-Schedule or offer the resource to PJM for scheduling as a PJM RTO-Scheduled Resource. In this section we focus primarily on the PJM Day-ahead Energy Market and the Control Area reliability-based scheduling process that takes place after the Day-ahead Energy Market is closed. Scheduling by PJM includes the Day-ahead Energy Market, the Control Area reliability-based scheduling process and the hourly scheduling process. The Day-ahead Energy Market bid/offer period closes at noon on the day before the Operating Day and the Day-ahead Market results are posted at 1600 on the day before the Operating Day. The Control Area reliability-based scheduling process occurs throughout



the day before the operating day. Hourly scheduling occurs up to sixty minutes prior to an hour during the Operating Day. During the scheduling process, PJM will:

Clear the Day-ahead Market and Day-ahead Scheduling Reserve Market based using Least-cost security constrained resource commitment and dispatch that simultaneously optimizes energy and reserves.

Determine a plan to reliably serve the hourly energy and reserve requirements of the PJM RTO by minimizing the cost to provide additional operating reserves above what was scheduled in the Day-ahead Market if required,

Perform hourly scheduling throughout the Operating Day as required.

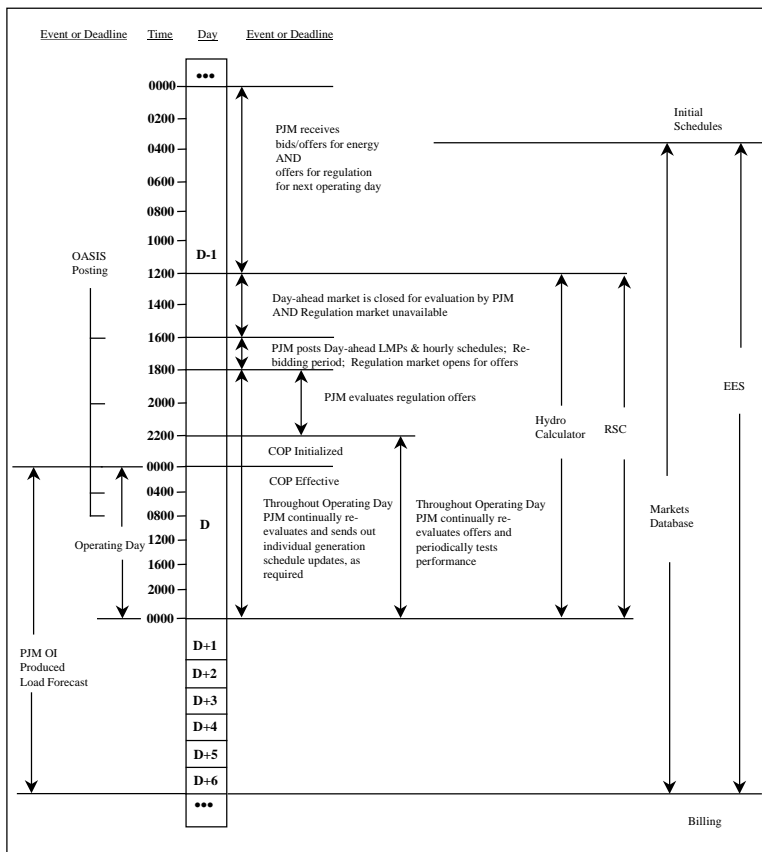




Exhibit 1: Scheduling Timeline

PJM Members submit their bids according to either actual cost or offer price as designated by the Operating Agreement of PJM Interconnection, L.L.C. for each generation resource.

In this manual, **Locational Marginal Price (LMP)** is defined as the marginal price for energy at the location where the energy is delivered or received. For accounting purposes, LMP is expressed in dollars per megawatt-hour (\$/MWh). In performing this LMP calculation, the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer is calculated as the sum of the following three components of Locational Marginal Price: System Energy Price, Congestion Price, and Loss Price. In this manual, unless otherwise specified, the terms “**LMP**” or “**Locational Marginal Price**” refer to the total LMP value including all three components. **For information on the concept of Locational Marginal Prices, please refer to Section 2 of this manual.**

1.1 PJM Responsibilities

In the Day-ahead Market, PJM determines the least-price means (minimizing production cost in terms of bid prices submitted) of satisfying the Demand bids, Decrement bids, operating reserves and other ancillary services requirements of the market buyers, including the reliability requirements of the PJM RTO. In addition to the Day-ahead Market scheduling process, PJM will also schedule resources to:

- Satisfy the reserve requirements of the PJM RTO by minimizing the cost to provide additional operating reserves above what was scheduled in the Day-ahead Market if required,
- Provide other ancillary services requirements of the market buyers,
- Satisfy all other reliability requirements of the PJM RTO. Specifically, PJM's responsibilities to support scheduling activities for all PJM Members include:

Develop the Day-ahead Market financial schedules based upon participant-supplied bids, offers and bilateral transaction schedules using least-cost security constrained resource commitment and dispatch analysis.



Post the following information after the Day-ahead Market clears at 4:00 p.m.:

- Schedules for Next Day by participant (generation & demand),
- Transaction Schedules,
- Day-ahead LMPs, Day-ahead Congestion Prices, & Day-ahead Loss Prices
- Day-ahead Binding Transmission Constraints,
- Day-ahead Net Tie Schedules,
- Day-ahead Reactive 500 kV Interface Indicator Limits,
- PJM Load Forecast,
- Aggregate Demand Bids
- PJM Day-ahead Scheduling Reserve (Operating Reserve) Objective.

Perform scheduling for the PJM Forecasted load and reserves not covered by the Day-ahead demand bids, Self-Scheduled Resources or Bilateral Transactions, including scheduling generation to relieve expected transmission constraints

Perform analysis to clear the Regulation Market and Synchronized Reserve Markets simultaneously and post the Regulation Marginal Clearing Price (RMCP) and Synchronized Reserve Marginal Clearing Price (SRMCP) on an hourly basis no later than 30 minutes prior to the start of the operating hour.

Maintain data and information which is related to generation facilities in the PJM RTO, as may be necessary to conduct the scheduling and dispatch of the PJM Interchange Energy Market and PJM RTO

Post the updated forecast of PJM Load and of the location and duration of any expected transmission congestion between areas in the PJM RTO

Revise schedule of resources to reflect updated projections of load, changing Bulk Electric System conditions, availability of and constraints of limited energy and other resources

1.2 PJM Market Participants Responsibilities

Only PJM Members are eligible to submit offers and purchase energy or related services in the Day-ahead Energy Market and in the Real-time Energy Market. PJM Members include Market Buyers and Market Sellers.

1.2.1 Market Buyers



There are two general types of Market Buyers:

- *Metered Market Buyer* – A Metered Market Buyer is a buyer that is purchasing energy from the PJM Interchange Energy Market for consumption by end-users inside the PJM RTO. A Metered Market Buyer may be further classified as a Generation Market Buyer. A Generation Market Buyer is a Metered Market Buyer that owns or has contractual rights to the output of generation resources that are capable of serving the Market Buyer’s load in the PJM RTO or selling energy-related services in the PJM Interchange Energy Market or elsewhere. By definition, all Market Buyers become Market Sellers upon approval of their applications.
- The scheduling responsibilities of a Metered Market Buyer are to:
 - Submit forecasts of customer loads for the next Operating Day
 - Submit economic load management agreements to PJM
 - Submit hourly schedules for Self-Scheduled Resource increments
 - Submit a forecast of the availability of each Generation Capacity Resource for the next seven days
 - Submit Offer Data for Generation Capacity Resources for supply of energy to the PJM Day-ahead Energy Market for the next day whether Self-Scheduled or PJM scheduled
 - Submit Bilateral Transactions for delivery within the PJM RTO, regardless of whether the generation is located inside or outside the PJM RTO
 - Submit optional Offer Data to supply Regulation Services in the PJM Regulation Market.
 - Submit optional Offer Data to supply Synchronized Reserve Services in the Synchronized Reserve Market.
- *Unmetered Market Buyer* – An Unmetered Market Buyer is a Market Buyer that is making purchases of energy from the PJM Interchange Energy Market for consumption by metered end-users or end-users that are located outside the PJM RTO.

Formatted: PJM Bullet 2

The scheduling responsibilities of an Unmetered Market Buyer are to:

- a. Submit optional requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the PJM Day-ahead Energy Market, along with Dispatch Rates (i.e. price-sensitive Demand Bids) above which it does not desire to purchase, if desired



- b. Purchase transmission capacity reservation in order to receive generation from PJM Interchange Energy Market if the energy is being delivered to end-users that are located outside the PJM RTO

1.2.2 Market Sellers

A Market Seller is a PJM Member that demonstrates to PJM that it meets the standards for the issuance of an order mandating the provision of transmission service under Section 211 of the Federal Power Act, submits an application to the PJM, and is approved by the Market Administrative Committee (see the PJM Manual for [Administrative Services for Operating Agreement of PJM Interconnection, L.L.C. \(M-33\)](#)).

The scheduling responsibilities of a market seller include:

- submit schedules for bilateral sales to entities outside the PJM RTO from within the PJM RTO
- submit optional offers for the supply of energy, capacity, and other services from Energy Resources into the Day-ahead Energy Market or the Real-time Energy Market for the next operating day only

1.2.3 Load Serving Entities

A Load Serving Entity (LSE) is any entity that has been granted authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users that are located within the PJM RTO. An LSE may be a Market Buyer or a Market Seller, as described above.

1.2.4 Curtailment Service Providers

A Curtailment Service Provider is a Member or Special Member, which acting on behalf of itself or one or more other Members or non-Members, participates in the PJM Interchange Energy Market by causing a reduction in demand.



Section 2: Overview of the PJM Energy Markets

Welcome to the Overview of the PJM Energy Markets section of the **PJM Manual for Energy & Ancillary Services Market Operations**. In this section you will find the following information:

- An overview description of the PJM Energy Markets (see “*Overview of PJM Energy Markets*”).
- A list of the PJM Two-Settlement Market Business Rules (see “*PJM Energy Markets Business Rules*”).

2.1 Overview of PJM Energy Markets

The PJM Energy Markets consists of two markets, a Day-ahead market and a Real-time balancing market. The Day-ahead Market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day based on generation offers, demand bids, Increment offers, Decrement bids and bilateral transaction schedules submitted into the Day-ahead Market. The balancing market is the real-time energy market in which the clearing prices are calculated every five minutes based on the actual system operations security-constrained economic dispatch. Separate accounting settlements are performed for each market, the Day-ahead Market settlement is based on scheduled hourly quantities and on day-ahead hourly prices, the balancing settlement is based on actual hourly (integrated) quantity deviations from day-ahead scheduled quantities and on real-time prices integrated over the hour. The day-ahead price calculations and the balancing (real-time) price calculations are based on the concept of Locational Marginal Pricing.

The Day-ahead Market enables participants to purchase and sell energy at binding Day-ahead Locational Marginal Prices (LMPs). The components of Day-ahead hourly LMPs are the Day-ahead System Energy Price, Day-ahead Congestion Price, and the Day-ahead Loss Price. It also allows transmission customers to schedule bilateral transactions at binding Day-ahead congestion charges based on the differences in the Congestion Prices between the transaction source and sink. Load Serving Entities (LSEs) may submit hourly demand schedules, including any price sensitive demand, for the amount of demand that they wish to lock-in at Day-ahead prices. Any generator that is a PJM generation capacity resource that has an RPM Resource Commitment must submit a bid schedule into the Day-ahead Market even if it is self-scheduled or unavailable due to outage. Other generators have the option to bid into the Day-ahead Market. Transmission customers may submit fixed, dispatchable or ‘up to’ congestion bid bilateral transaction schedules into the Day-ahead Market and may specify whether they are willing to pay congestion charges or wish to be curtailed if congestion occurs in the Real-time Market. Curtailment Service Providers (CSPs) may submit demand reduction bids. All spot purchases and sales in the Day-ahead



Market are settled at the Day-ahead prices. Congestion that results from the Day-ahead sales and purchases of energy is settled at the Day-ahead Congestion Price component of LMP. Transmission losses that result from the Day-ahead sales and purchases of energy are settled at the Day-ahead Loss Price component of LMP. After the daily quote period closes, PJM will calculate the Day-ahead schedule based on the bids, offers and schedules submitted, using the scheduling programs described in Section 2 of this manual, based on least-cost, security constrained resource commitment and dispatch for each hour of the next operating day. The Day-ahead scheduling process will incorporate PJM reliability requirements and reserve obligations into the analysis. The resulting Day-ahead hourly schedules and Day-ahead LMPs represent binding financial commitments to the market participants. Financial Transmission Rights (FTRs) are accounted for at the Day-ahead Congestion Price component of LMP values (see the [PJM Manual for Financial Transmission Rights \(M-06\)](#)).

The Real-time Energy Market is based on actual real-time operations. Generators that are PJM capacity resources and Demand Resources that are available but not selected in the day-ahead scheduling may alter their bids for use in the Real-time Energy Market during the Generation Rebidding Period from 4:00 PM to 6:00 PM (otherwise the original bids remain in effect for the balancing market). Real-time LMPs are calculated based on actual system operating conditions as described by the PJM state estimator. LSEs will pay the Real-time LMPs for any demand that exceeds their Day-ahead scheduled quantities (and will receive revenue for demand deviations below their scheduled quantities). In the energy market, generators are paid the Real-time LMPs for any generation that exceeds their day-ahead scheduled quantities (and will pay for generation deviations below their scheduled quantities). Transmission customers pay congestion charges based on the real-time Congestion Price component of LMPs for bilateral transaction quantity deviations from Day-ahead schedules. CSPs may self schedule demand reductions for Demand Resources not dispatched in real-time by PJM. All spot purchases and sales in the balancing market are settled at the real-time LMPs. Congestion that results from the Real-time sales and purchased of energy is settled at the Real-time Congestion Price component of LMP. Transmission losses that result from the Real-time sales and purchased of energy are settled at the Real-time Loss Price component of LMP.

2.2 Definition of Locational Marginal Price

Locational Marginal Price (LMP) is defined as the marginal price for energy at the location where the energy is delivered or received. For accounting purposes, LMP is expressed in dollars per megawatt-hour (\$/MWh). LMP is a pricing approach that addresses Transmission System congestion and loss costs, as well as energy costs. Therefore, each spot market energy customer pays an energy price that includes the full marginal cost of delivering an increment of energy to the purchaser's location.



- When there is transmission congestion in PJM, the PJM dispatcher dispatches one or more of the generating units out of economic merit order to keep transmission flows within limits. There may be many resources that are dispatched to relieve the congestion. The LMP reflects the cost of redispatch for out-of-merit resources and cost of delivering energy to that location.
- LMPs are calculated at all injections, withdrawals, EHV (nominal voltage of 500 KV and above), Interfaces, and various aggregations of these points.
- LMPS are calculated in both the Real-time Energy Market and Day-ahead Energy Market.
- The LMP calculation calculates the full marginal cost of serving an increment of load at each bus from each resource associated with an eligible energy offer as the sum of three separate components of LMP. In performing this LMP calculation, the cost of serving an increment of load at each bus from each resource associated with an eligible energy offer is calculated as the sum of the following three components of Locational Marginal Price:
 - **System Energy Price** - is the price at which the Market Seller has offered to supply an additional increment of energy from a generation resource or decrease an increment of energy being consumed by a Demand Resource.
 - **Congestion Price** - is the effect on transmission congestion costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission line loadings.
 - **Loss Price** - is the effect on transmission loss costs (whether positive or negative) associated with increasing the output of a generation resource or decreasing the consumption by a Demand Resource, based on the effect of increased generation from or consumption by the resource on transmission losses.
- The energy offer or offers that can serve an increment of load at a bus at the lowest cost, calculated in this manner, shall determine the Locational Marginal Price at that bus.

2.3 Energy Market Business Rules

2.3.1 Bidding & Operations Time Line:

The day-ahead scheduling/bidding timeline for PJM energy markets consists of the following time frames:

- **1200** — Day-ahead Market bid period closes. All bids must be submitted to PJM. At 1200 PJM begins to run the day-ahead market clearing software to determine the hourly commitment schedules and the LMPs for the Day-ahead Market. This is the



first resource commitment run, which determines the resource commitment profile that satisfies the fixed demand, cleared price-sensitive demand bids, cleared demand reduction bids, and PJM Day-ahead Scheduling Reserve (Operating Reserve) objectives, while minimizing the total production cost (subject to certain limitations) for energy and reserves. This commitment analysis also includes external bilateral transaction schedules and external resource offers into the PJM Day-ahead Market.

- **1600** — PJM posts the day-ahead hourly schedules and LMPs in the eMKT System, based on the first resource commitment. PJM also makes these results available in downloadable files, via the eMKT System, or a dedicated communication link.
- **1600 - 1800** — PJM opens the balancing market offer period. During this time, market participants can submit revised offers for resources not selected in the first commitment. However if the market participant self-scheduled their unit in the Day-ahead Market, they cannot change the unit status to economic in the rebid period.
- **1800** — The balancing market offer period closes. PJM performs a second resource commitment, which includes the updated offers, updated resource availability information, and updated PJM load forecast information and load forecast deviation. The focus of this commitment is reliability and the objective is to minimize start-up and no load costs for any additional resources that are committed.
- **1800 - Operating Day** — PJM may perform additional resource commitment runs, as necessary, based on updated PJM load forecasts and updated resource availability information. PJM sends out individual generation schedules updates to specific generation owners only, as required.

2.3.2 Market Buyers

The following business rules apply to Market Buyers:

- Each Market Participant's profile (which is defined by PJM) shall specify the transmission zones or buses for which that participant is eligible to submit demand bids.
- Market Buyers may submit hourly demand quantities for which it commits to purchase energy at day-ahead prices for consumption in the next Operating Day. Quantity bids must specify MW quantity and location (transmission zone, aggregate, or single bus).
- Demand bids are assumed to exclude losses (transmission zone losses and share of 500 kV losses).
- Price sensitive demand bids shall specify MW quantity, location (transmission zone, aggregate, or single bus), and the price at which the demand shall be curtailed.
- Price sensitive demand bids are accepted in single bid blocks only. Up to nine bid blocks may be submitted per market participant at a specific location.



- If a Market Buyer submits no day-ahead bid information, then a zero MW quantity is assumed.
- For the Day-ahead Market, the Electric Distribution Company (EDC) shall specify the transmission zone, bus distributions, and aggregate bus distributions as a daily distribution. The default distribution for a transmission zone for the Day-ahead Market is the state estimator distribution for that zone at 8:00 a.m. one week prior to the Operating Day (i.e. if next Operating Day is Monday, the default distribution is from 8:00 a.m. on Monday of the previous week).
- The EDC may update the default distribution factors only after the state estimator populates the default.
- EDCs shall submit a forecast of demand within their transmission zone. This is for reliability purposes only (and does not, therefore, require a binding bid).
- A Market Buyer that is not an LSE or purchasing on behalf of an LSE is not required to purchase transmission service for purchases from the PJM Market to cover deviation from its sales in a day-ahead market.
- The list of transmission zones, aggregates, and single buses at which demand bids are accepted is defined by PJM.
- Market Buyers may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interface point (posted on the PJM Web site) for which an LMP is calculated. It is not required that physical generation or load exists at the location that is specified in the increment offer or decrement bid.
- Price-sensitive demand bids, increment offers, and decrement bids must be consistent with the \$1000/MWh price cap.

2.3.3 Market Sellers

The following business rules apply to Market Sellers:

- Self-scheduled generation shall submit an hourly MW schedule.
- Generators that are Capacity Resources shall submit offers into the Day-ahead Market, even if they are unavailable due to forced, planned, or maintenance outages.
- Generators that are Capacity Resources and are self-scheduling shall submit offer data in the event that they are called upon during emergency procedures.
- Generation Capacity Resources shall submit a schedule of availability for the next seven days and may submit non-binding offer prices for the days beyond the next Operating Day.



- The set of offer data last submitted for each Generation Capacity Resource shall remain in effect for each day until specifically superseded by subsequent offers.
- If a Generation Capacity Resource is not scheduled in the Day-ahead Market, it may revise its offer and submit into the real-time market or it may self-schedule the resource.
- Generation owners planning to run generation resources scheduled in the Day-ahead Markets are required to call the PJM Control Center at least 20 minutes prior to bringing the unit online. Generation owners of self-scheduled generation resources must also provide at least 20 minutes notice.
- Generation resources that are scheduled in the Day-ahead Market have a financial obligation to sell their output in real-time. Provisions exist in the Tariff that permit make whole payments to be made to those combustion turbines that are scheduled in the Day-ahead Market and then not called on in real-time by PJM that are further defined in PJM Manual M-28.
- Generation Capacity Resources that have notification, startup, and minimum run times that exceed 24 hours must submit binding offer prices for the next seven days.
- Each Generation Capacity Resource must make available at least one cost-based schedule and if it falls within the types of generators in the PJM Unit Parameter matrix it must also submit a Price Based Parameter Limited Schedule.
- Generation offers may consist of startup, no-load, and incremental energy offer. A generation offer may not exceed \$1000/MWh.
- Energy resources may offer into the Day-ahead Market or Real-time Market.
- If an Energy resource does not submit offer data, then the offer is assumed to be a zero MW quantity.
- Intermittent Generation Resources, that are Capacity Resources, shall meet the must offer requirement by either self-scheduling (Availability = Must Run) or may allow the Day-ahead Market to schedule by offering the unit as an dispatchable resource (Availability = Economic) .
- The hourly Day-ahead self-scheduled values for intermittent resources may vary hour to hour from the capacity obligation value,
- Two single price-based schedules may be offered into the Day-ahead Market. One schedule must be a price based parameter limited schedule. The price-based parameter-limited schedule may be unavailable, and if it is, the “use max gen” flag must be set to “yes”. The price-based parameter limited schedule will be committed during Maximum Generation Emergency if it is unavailable in the Day Ahead Market and the “use max gen” flag is set to “yes”. The second price schedule is a price-based schedule that is not parameter limited. One of these two price schedules must be available in the



Day Ahead Market. In addition to the price-based schedule, one cost-based schedule shall be made available for PJM's use in the event that the resource is used to control a transmission constraint. The cost based schedule shall be parameter-limited.

- A generator offer that is accepted for the Day-ahead Market automatically carries over into the balancing market.
- Only a single price-based offer may be submitted into the balancing market.
- A generator offer for a generating unit with combined cycle capability shall make available either the schedule for the CTs or the schedule for the combined cycle unit, not both.
- Only CTs may submit weather curves, which specify MW limits for CTs as a function of temperature.
- Forecast points shall consist of a daytime temperature and a nighttime temperature.
- There are separate weather curves for economic MW and for emergency MW.
- Each CT is assigned to a weather point, which is entered by the Operating Company. As generating units change ownership it may be necessary to add weather points. The default for the weather points is the PJM temperature forecast.
- The priority of generator offer operating limits are as follows: (1) Unit Hourly MW limits (eMKT Unit Hourly Updates), (2) Daily Unit Schedule Limits (eMKT Schedule Detail), (3) Unit limits (eMKT Unit Detail). Daily unit schedule MW limits can be overridden by unit hourly MW limits. Weather curves for CTs apply to both unit limits and schedule limits.
- Market Sellers may submit increment offers or decrement bids at any hub, transmission zone, aggregate, single bus or eligible external interface point (posted on the PJM Web site) for which an LMP is calculated. It is not required that physical generation or load exists at the location that is specified in the increment offer or decrement bid.
- A price-based unit has the option to choose cost-based start-up and no-load fees. A price-based unit that chooses the cost based option may change the start-up and no-load fees daily. A priced-based unit that chooses the price based option will continue to be able to change the start-up and no-load fees twice a year.
- The choice between using cost-based and price-based startup and no-load fees can be made twice a year during the same open enrollment window (on or before 1200 hours March 31 for the period April 1 through September 30 and on or before 1200 hours September 30 for the period October 1 through March 31). Period 1 is defined as the period of time beginning April 1 and ending September 30. Period 2 is defined as the period of time beginning October 1 and ending March 31. If a priced based unit chooses the cost-based start-up and no-load fees option, the decision cannot be changed until the next open enrollment period takes place.



- When a unit or part of a unit is designated as Maximum Emergency (ME), this means that the referenced output levels may require extraordinary procedures and that the designated MW is available to PJM only when PJM requests Maximum Emergency Generation. Designation of a unit or a portion of a unit as ME should be based on the real operating characteristics of the unit and not be used to withhold all or a portion of the capacity of a unit from the Day-ahead Market.

Designation of all or part of a unit's capacity as Maximum Emergency (ME) constitutes withholding in the Day-ahead Market, if:

- The capacity is not designated as ME in the bid for the Real-time Market, or;
- There is no physical reason to designate the unit as ME.

The consequence of withholding a unit's capacity under ME is:

- The unit will be given an outage ticket which reflects a de-rating equal to the positive difference in capacity designated Maximum Emergency in the bid for the Day-ahead Market and capacity designated Maximum Emergency in the bid for the Real-time Market.
- A unit bid includes an Economic Maximum point, which is the highest output on its bid curve that the unit is offering for economic dispatch. The Economic Max represents the highest unrestricted level of MW that the operating company will operate the unit, under its offer, for economic dispatch. The Economic Max point should be based on the actual capability of the unit to operate on its bid curve and should not be used to withhold a portion of the capacity of a unit from the Day-ahead Market.

Reduction of Economic Max MW constitutes withholding in the Day-ahead Energy Market, if:

- The Economic Max MW is higher in the bid for the Real-time Energy Market than in the bid for the Day-ahead Market, or;
- There is no physical reason to designate a lower Economic Max in the bid for the Day-ahead Market bid than in the bid for the Real-time Market.

- The consequence of withholding a unit's capacity by reduction of Economic Max MW is:

- The unit will be given an outage ticket which reflects a derating equal to the positive difference in Economic Max output designated in the bid for the Real-time Market and in the bid for the Day-ahead Market.
- Generating units that are connected to the system at the same electrical location may be aggregated and offered into the PJM market as a single unit.

- The aggregated unit must be offered into the PJM markets as a single unit with only one set of offer data, including startup, no load and incremental energy. This rule applies to all energy and ancillary service markets into which the unit is offered.

Formatted: PJM Bullet 2, No bullets or numbering



- Hourly integrated, revenue quality meter data must be submitted to eMeter on the basis of the aggregated unit.
- Real-time meter data is required for each physical unit in order to support the PJM state estimator model and to allow energy settlement on an individual unit level.
- Balancing Operating Reserve deviations for aggregated units will be calculated based on the hourly aggregated unit output as defined in ***PJM Manual 28: Operating Agreement Accounting, Section Operating Reserve Accounting.***
- Balancing Operating Reserve Generator deviations for units deemed to be “not following dispatch” that occur at a single bus will be able to offset one another.
- A “single bus” will be any unit located at the same site and that has the identical electrical impacts on the transmission system. Units are deemed to have identical electrical impacts on the transmission system if they meet the following criteria:
 - Units that have identical dfax to the system
 - Units that are on the same low side of the bus (i.e. connected at same voltage level)
- In the case of units on busses with bus-tie breaker, if bus-tie breaker was open less than 5% of the hours in the previous 3 years, supplier netting of units will be allowed across this bus-tie breaker.
- PJM will maintain a list of units that are deemed to have identical electrical impacts on the transmission system to be used for Balancing Operating Settlement. PJM will review the list on an annual basis. Generators will be reviewed as needed during any new generation activation or reconfiguration process as defined in ***Section 7 of PJM Manual 14d: Generator Operational Requirements.***
- Unit parameters do not have to be identical for the units’ deviation MW to offset one another.
- If multiple units are deemed “not following dispatch” at a single bus, the deviation MW and direction of each unit at that bus will be summed to determine the deviation MW at that bus.
- Units at a “single bus” must be owned or marketed by single PJM Market Participant.
- Unit modeling changes in the PJM eMKT system (unit type, aggregation level, for example), not including changes based on physical changes at the plant, can be made at the beginning of each quarter.
- CT’s are permitted to provide an Economic Minimum less than the physical economic minimum value of the unit. Per the ***PJM Manual for Operating Agreement***

Formatted: PJM Bullet 2, No bullets or numbering



Accounting, for settlement purposes, PJM determines the resource's hourly UDS LMP Desired MWh based on its dispatch rate, offer data, and minimum and maximum energy limits for that hour. For steam units, the lesser of the day-ahead scheduled and real-time economic minimum limits, and the greater of the day-ahead scheduled and real-time economic maximum limits, are used. For CT's, operating at PJM direction, the actual real-time output is used as the UDS LMP Desired MWh value.

2.3.4 Minimum Generator Operating Parameters – Parameter Limited Schedules

Below is the list of business rules to require units to submit schedules that meet minimum accepted parameters.

- Pre-determined limits on non-price offer parameters for all generation resources will define limits on generation resources' non-price offer parameters under the following circumstances:
- If the three pivotal supplier test for the operating reserve market defined by transmission constraint(s) is failed, generation resources will be committed on their Parameter-Limited Schedule, as defined below.
- The Parameter-Limited Schedule that is utilized shall be the less limiting of the defined Parameter-Limited Schedules or the submitted offer parameters.
- In the event that the Office of the Interconnection: (i) declares a Maximum Generation Emergency; (ii) issues an alert that a Maximum Generation Emergency may be declared ("Maximum Generation Emergency Alert"); or (iii) schedules units based on the anticipation of a Maximum Generation Emergency or a Maximum Generation Emergency Alert for all or any part of such Operating Day, generation resources will be committed on their Parameter-Limited Schedule.
- On an annual basis, PJM will define a list of minimum acceptable operating parameters, based on an analysis of historically submitted offers, for each unit class for the following parameters¹:
 - Turn Down Ratio
 - Minimum Down Time
 - Minimum Run Time

Formatted: PJM Bullet 2, No bullets or numbering

¹ As defined in the PJM Manuals and Markets Database Dictionary.



- Maximum Daily Starts
- Maximum Weekly Starts
- The following parameters² will be reviewed on an ongoing basis, via a stakeholder process, and may, at some future date, define limitations for:
 - Hot Start Notification Time
 - Warm Start Notification Time
 - Cold Start Notification Time
- The operating parameters for each unit class must meet the historically based criteria listed in the rules below. The operating parameter limits will remain in place unless an exception is filed and approved (see rules below).
- Turn Down Ratio is defined as the ratio of economic maximum MW to economic minimum MW.
- The minimum acceptable Turn Down Ratio applicable to an individual unit will be the greater of:
 - a) The difference between the minimum of the economic minima and the maximum of the economic maxima submitted over the prior 24 months, or
 - b) 90 percent of the PJM-defined unit class Turn Down Ratio.
- If the resulting unit Turn Down Ratio is less than 90 percent of the PJM-defined unit class Turn Down Ratio, then the unit's Turn Down Ratio will be set equal to 90 percent of PJM-defined unit class Turn Down Ratio.
- For CTs, the Turn Down Ratio will assumed to be 1.0.
- The submitted Minimum Run Time may not exceed the defined Minimum Run Time for the PJM-defined unit class.
- The initial Minimum Down Time for each unit is based on the minimum of the Minimum Down Times submitted over the prior 24 months, if the resultant minimum down time is less than or equal to 110 percent of the PJM-defined unit class Minimum Down Time.

Formatted: PJM Bullet 2, No bullets or numbering

² As defined in the PJM Manuals and Markets Database Dictionary.



- If Minimum Down Time submitted for a unit is more than 110 percent of the PJM-defined unit class Minimum Down Time, then the unit's Minimum Down Time will be set equal to 110 percent of the PJM-defined unit class Minimum Down Time.
- The initial Maximum Starts per Week for a unit will be based on the posted level for the PJM-defined unit class.
- If the Maximum Starts Per Week submitted for a unit is less than the PJM-defined unit class maximum starts per week, then the unit's Maximum Starts per Week will be set equal to the PJM-defined unit class posted Maximum Starts per Week.
- The Maximum Starts Per Day will be based on the PJM-defined unit class for non-CT units. For CT units, the minimum value of maximum starts per day will be 2.
- If the number of Maximum Daily Starts submitted by a unit is less than the PJM-defined unit class Starts per Day for a non-CT unit, or less than 2 for a CT, then the unit's Maximum Starts per Day will be set equal to the PJM-defined unit class Maximum Starts per Day for a non-CT unit and 2 for a CT.
- Generation resources will be required to submit an additional price schedule specifying the unit's predefined non-price parameter limits. This schedule will be identified as the unit's "parameter limited" schedule. The unit's cost-based schedule(s) to be used when the unit is offer-capped for transmission will also need to include the same parameters as the Parameter-Limited Schedule.
- The Market Monitoring Unit shall review the Parameter Limited Schedule Matrix , included in Section 6.6(c) of Schedule 1 of the Operating Agreement, twice yearly, and, in the event it determines that revision is appropriate, shall provide a revised matrix to the Office of the Interconnection by no later than December 31 and June 30, respectively, prior to the bi-annual enrollment periods for the submission of start-up and no-load costs. Period 1 is defined as the period of time beginning April 1 and ending September 30. Period 2 will be defined as the period of time beginning October 1 and ending March 31. Pursuant to section II.B of Attachment M – Appendix of the Tariff, exception requests for Period 1 must be received by the Market Monitoring Unit by no later than February 28, and exception requests for Period 2 must be received by the Market Monitoring Unit by no later than August 31 prior to each period, all generation suppliers that wish to submit a Parameter-Limited Schedule for units with physical operational limitations that prevent the units from meeting the minimum parameters may submit a request for a new exception via eMKT for evaluation. Each generation supplier must supply the required historical unit operating data in support of the exception and if the exception requested is based on new physical operational limits for the resource for which historical operating data is unavailable, the generation resource may also submit technical information about the physical operational limits for period exceptions of the resource to support the requested parameters.



- Physical operational limitations for period exceptions may include but are not limited to, metallurgical restrictions due to age and long term degradation; physical design modifications; operating permit limitations; operating limits imposed by federal, state or local regulatory requirements or insurance carrier requirements; consent decrees; manufacturer technical bulletins; or environmental permit limitations under non-emergency conditions. Each generation supplier requesting an exception based on new physical operational limitations for a unit may submit the technical information, required due to the unavailability of historical operating data, supporting the requested parameters, which must be based on the definition of physical operational limitations for period exceptions of the unit. PJM and the MMU will review the operations of the unit after each of the first three full years of operation to verify the requested parameters. The exception will not be accepted thereafter if not supported by the operating data.
- Each requested exception will indicate the expected duration of the requested exception including the date on which the requested exception period will end. If physical conditions at the unit change such that the exception is no longer required, the generation supplier is obligated to inform PJM and the exception will be reviewed to determine if the exception continues to be appropriate.
- PJM and the MMU review the exception and provide the generation supplier with a decision within ten (10) business days. Should PJM require additional technical expertise in order to evaluate the exception request, PJM will engage the services of a consultant with the required expertise. All Parameter-Limited Schedules must be submitted in eMKT seven days prior to the beginning of period 1 and period 2, defined as April 1 and October 1, respectively.
- On a daily basis, each generation supplier may submit notification to PJM that changed physical operational limitations at the unit require a temporary exception to the unit's parameters. Each generation supplier must supply the required unit operating data in support of the exception.
- The process and timeline for submitting a daily exception is as follows:
 - By 10 a.m. prior to the close of DAM
 - Initial Deadline to request a parameter exception that will begin the next operating day
 - PLS Schedules (both Price & Cost) will be revised in eMKT to change the parameter limit for the next operating day
 - Daily Exception Requests should be submitted via eMKT
 - By 4 p.m. prior to operating day (close of the DAM)
- PJM must receive a complete exception request that includes:

Formatted: PJM Bullet 2, No bullets or numbering



- Unit Name
 - Parameter Limit Requested
 - Reason for Daily Exception Request
 - eDart ticket
 - Justification for Daily Exception Request, including required unit operating data in support of the exception
 - Date on which the exception period will end. Exceptions granted may not continue past the beginning of the next period.
- If PJM does not receive a complete exception request, and the unit did not clear in the DAM, the unit schedule will returned to its previous parameter limits.
 - Physical operational limitations for daily exceptions may include, but are not limited to, short term equipment failures, short term fuel quality problems such as excessive moisture in coal fired units, or environmental permit limitations under non-emergency conditions.
 - In addition, physical operational limitations for daily exceptions may include any physical operational limitation for period exceptions that arises during the six month period to which period exceptions apply. For steam units, regardless of fuel type, the average historical values for any of the parameters as offered by the owners for the calendar year 2006 may be used in place of the values in the matrix.
 - For steam units, regardless of fuel type, the historical average is calculated from the market based offers for market based units and from cost-based offers for units that made only cost-based offers.
 - For combined cycle units:
 - If the 2006 average historical market-based offer parameters are within the limits in the parameter matrix, the unit will be limited to that 2006 historical average. If not then ii) applies;
 - If the unit was offered with market-based offer parameters for 10% or more of the days (36 days minimum) at a level at or more flexible than parameters in matrix, the unit will be limited at that level. If not the iii) applies
 - If the 2006 average historical market based offer parameters exceed the limits in the matrix (less flexible than the parameters in the matrix) then the unit will be limited to the level at which the market-based parameter was bid to the most flexible level for 10% or more of the days (36 days minimum) at that level.

Formatted: PJM Bullet 2, No bullets or numbering

Formatted: PJM Bullet 2, No bullets or numbering



- Each generation supplier will provide a date on which the exception period will end. Exceptions granted pursuant to Business Rule #27 may not continue past the beginning of the next period. Such exceptions will be accepted, but will be subject to after-the-fact review by PJM, and the MMU provided that the after-the-fact review shall be limited to the continuation of the exception. If physical conditions at the unit change such that the exception is no longer required, the generation supplier is obligated to inform PJM and the exception will be terminated.
- If an exception request is denied by PJM in part or in full, the generation supplier may choose to dispute the decision via the Dispute Resolution Process as defined in the PJM Operating Agreement. While under dispute, the generation supplier will be required to submit parameter-limited schedules for the period as determined during the exception process.
- Generation suppliers may indicate to PJM those units with the ability to operate on multiple fuels. Multiple-fuel units may submit a parameter-limited schedule associated with each fuel type. All Parameter-Limited Schedules must be submitted via eMKT seven days prior to the beginning of each period. The generation supplier will be required to indicate to PJM which of the parameter-limited schedules are available each day by using the eMKT use max gen flag. Any exceptions required for any of the parameter-limited schedules submitted for multiple-fuel units will be required to be submitted and approved via the exception process.
- Nuclear Units are excluded from eligibility for Operating Reserve payments except in cases where PJM requests that nuclear units reduces output at PJM's direction or where a physical problem at a nuclear unit requires a risk premium and that risk premium is submitted to and accepted by the MMU. Other specific circumstances will be evaluated on a case-by-case basis by PJM and the MMU.

The following business rules apply to Transmission Customers:

- Transmission customers may submit external bilateral transaction schedules and may indicate willingness to pay congestion charges into either the Day-ahead Market or balancing market. In the Day-ahead Market, a transaction shall indicate willingness to pay congestion charges by submitting the transaction as an 'up to' congestion bid.
- 'Up to' congestion bids shall be no greater than \$50/MWh, and no less than -\$50/MWh. Any 'up to' congestion transaction that bids higher than \$50/MWh or less than -\$50/MWh will be rejected.
- PJM will maintain an up-to date list of source/sink combinations that will be available for 'Up to' congestion bidding on the PJM OASIS.
- Internal bilateral transactions may be designated as day-ahead or balancing market in PJM eSchedules.



- Up-to congestion bids, increment offers, and decrement bids shall be supported in the Day-ahead Market only.
- ‘Up to’ congestion bids are cleared based on the total LMP price difference between the source and the sink.

2.3.5 Curtailment Service Providers

The business rules that apply to Curtailment Service Providers are set forth in Section 10.

2.3.6 PJM Activities

The following business rules apply to PJM activities:

- PJM shall post on the eMKT System, the PJM load forecast, total bid demand, and Day-ahead Scheduling Reserve (Operating Reserve) objective for each hour of the next Operating Day by 1600 at the completion of the day-ahead scheduling process.
- PJM shall post forecasts of total hourly demand for the next four days and peak demand for the subsequent three days.
- PJM shall post hourly LMP, Congestion Price, and Loss Price values for the next operating day at the completion of the day-ahead scheduling process at 1600.
- PJM shall post the schedule of demand, supply, and bilateral transactions for private viewing by market participants.
- PJM may perform supplemental resource commitments after the day-ahead schedule is posted in order to maintain reliable operation. Such supplemental commitments are based on minimizing startup and no-load costs.
- During the various resource commitment analyses, PJM may limit its dependence on Combustion Turbines to provide reserves in order to maintain reliable operational standards. Such limits shall be based on past performance of these units.
- PJM's market power mitigation procedure continues under the energy market procedure. If transmission limits are identified during the day-ahead scheduling process or during real-time operations, the appropriate generators (those for which the owner fails the Three-Pivotal Supplier Test as detailed in Section 6.4.1 paragraphs (e) and (f) of the PJM Operating Agreement) are offer-capped.
- Units are offer-capped at lesser of their cost-based or price-based schedules, including start-up and no-load components. Specific details regarding determination of cost-based offers may be found in PJM Manual M-15 (Cost Development Guidelines) and Section 6.4.2 of the PJM Operating Agreement.



- For the Day-ahead Market, the offer caps will apply for the length of time the unit is scheduled.
- Non-CT units offer-capped in the Day-ahead Market will be offer-capped in the real-time market.
- Units offer-capped in the real-time market shall remain offer-capped until the unit's minimum run time is exhausted. Once the minimum run time for a particular unit expires in the real-time market, if that unit is no longer needed to control any of the constraints for which it was originally started but the unit is kept on-line, the decision as to whether the unit remains offer-capped will be made as follows:
 - If PJM needs the unit for economics (on its price-based offer) and the unit is not required to relieve a current or anticipated constraint, the unit will be uncapped.
 - If released by PJM, any subsequent offer-capping decision for a unit will be determined by the Three-Pivotal Supplier Test.
 - Units remain eligible to set LMP when offer-capped.
- Offer-capping is suspended in Scarcity Pricing Regions during scarcity conditions, as defined and detailed in Section 6A of the PJM Operating Agreement and PJM Manual M-13 (Emergency Procedures).
- Units brought on-line for economics prior to constrained conditions will not be offer-capped.
- Once the price-based switch is set to price (set by PJM upon request from generation owner), the generator owner cannot return to a cost-based offer (cost-capped or historic LMP-capped).
- Price-sensitive demand can set LMP in the Day-ahead Market. (Due to communication infrastructure challenges, price-sensitive demand cannot currently set LMP in the real-time market.)

Formatted: PJM Bullet 2, No bullets or numbering

2.3.7 Mechanical/Technical Rules

- A valid generator offer consists of the following elements:
 - For an internal Generation Capacity Resource a valid generator offer consists of a price-based schedule (if the unit has switched to price) and at least one cost-based schedule. The default values for the schedules are:
 - Day-ahead Market switch is yes (1).

Formatted: PJM Bullet 2, No bullets or numbering



- Balancing market switch is yes (1).
- Use start-up & no-load switch is yes (1).
- Use offer slope switch is no (0).
- Condense available switch is blank or no (0).
- Startup and no load costs are zero.
- Hourly economic max/min and emergency max/min are the unit level economic and emergency MW limits, respectively.
- Minimum down time, minimum run time, start times, and notification times are zero.
- Maximum run time and maximum number of starts per week are infinity.
- The default for incremental offer curve data is \$0. If the last MW point on the segment curve is less than the maximum emergency limit, then the curve is extended up to the emergency maximum limit using zero slope from the last incremental point on the curve.
- For an external resource or a non-Capacity Resource, a valid generator offer consists of a price-based schedule. The default values for the schedules are:
 - Day-ahead Market switch is yes (1).
 - Balancing market switch is yes (1).
 - Use start-up & no-load switch is yes (1).
 - Use offer slope switch is no (0).
 - Condense available switch is blank or no (0).
 - Startup and no-load costs are zero.
 - Hourly economic max/min and emergency max/min are the unit level economic and emergency MW limits, respectively.
 - Minimum down time, minimum run time, start times, and notification times are zero.
 - Maximum run time and maximum number of starts per week are infinity.



- The default for incremental offer curve data is \$0. If the last MW point on the segment curve is less than the maximum emergency limit, then the curve is extended up to the emergency maximum limit using zero slope from the last incremental point on the curve.
- Valid offers for demand bids, price sensitive and fixed, consist of the following items:
 - MW, with a default value of 0 MW. Demand bids should not include losses.
 - Location (transmission zone, aggregate, or single bus)
 - Price at which demand shall be curtailed (for price-sensitive bids)

2.3.8 Modeling

- Fixed transactions, including increment offers and decrement bids, are modeled in the Resource Commitment. Up-to congestion transactions are not modeled in the commitment, but are handled in the day-ahead dispatch. PJM does not commit additional generation to support up-to congestion transactions.
- The day-ahead security analysis treats increment offers and decrement bids injections as distributed load (or generation) that create an imbalance where physical load and generation do not exist.
- External bilateral transactions with source = interface bus are modeled as generation at the source bus location. This is the case for both dispatchable and non-dispatchable transactions.
- External bilateral transactions with sink = interface bus are modeled as a load at the sink bus location. This is the case for both dispatchable and non-dispatchable transactions.
- Only fixed transactions and transactions involving external aggregate resources are modeled in the Resource Commitment (RSC) for the Day-ahead Market.

2.3.9 Day-ahead Locational Marginal Price (LMP) Calculations

- The day-ahead LMP calculation is based on the first resource commitment, which has the objective to satisfy the day-ahead bid demand, plus the PJM Day-ahead Scheduling Reserve (Operating Reserve) objective requirement for that level of bid demand. The calculation co-optimizes Day-ahead Scheduling Reserve (DASR) and Day-ahead (DA) energy prices.
- The following resources are eligible to set LMP values in the Day-ahead Market:



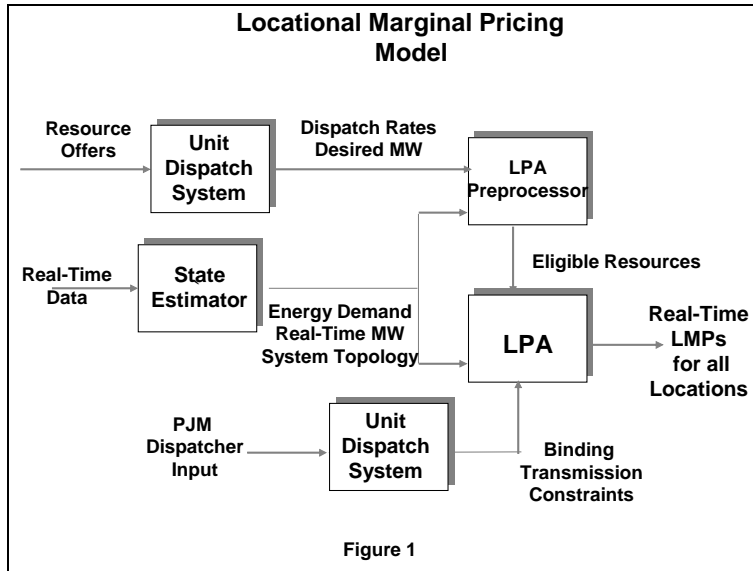
- all pool-dispatchable steam units
 - pool-scheduled CTs and diesels whose bid price is at or below the system marginal cost
 - dispatchable external resource offers
 - increment offers
 - committed Economic Load Response bids
- Demand bids that are eligible to set LMP values in the Day-ahead Market are price-sensitive demand bids and decrement bids.
 - Transactions that bid 'up to' congestion charges are eligible to set LMP values in the Day-ahead Market.
 - Settlements Data Requirements can be found in M28: Operating Agreement Accounting.

Formatted: PJM Bullet 2, No bullets or numbering

2.4 Real-time Locational Marginal Price (LMP) Calculations

The PJM Real-time Locational Marginal Price (LMP) calculation process consists of several programming modules that are executed as part of the real-time sequence. The real-time sequence executes every five minutes on the PJM Energy Management System (EMS). A functional diagram of the PJM LMP Model is shown in Figure 1. As indicated in Figure 1, the main modules of the PJM LMP Model are:

- Unit Dispatch System (UDS)
- PJM State Estimator
- LPA Preprocessor
- Locational Pricing Algorithm (LPA)



Each of the PJM LMP modules is described in detail below.

2.5 Unit Dispatch System

The Unit Dispatch System (UDS) is a software tool that provides the PJM dispatchers with the capability to manage changes in load, generation, interchange, and transmission constraints simultaneously on a near real-time basis, by providing recommended dispatch solutions. The UDS evaluates various system conditions to produce a dispatch solution for a user-selected look-ahead time. This allows the operator to simultaneously manage multiple transmission constraints.

The Unit Dispatch System is not a stand-alone system. It is an application that processes data from the markets database and other PJM systems. UDS executes a dispatch solution automatically every five minutes or when executed by the operator. To calculate the solution, UDS looks at online and available resources, resource offer data, forecasted load, scheduled and current interchange, ACE (Area Control Error), as well as various other input parameters.

Real-time data sources include:

- Load forecast data from EMS
- ACE, steam deviation, regulation signal from EMS



- Constraint data - unit sensitivities from EMS
- State Estimator output from EMS
- Outage data from eDART
- Transaction data from EES

The application then produces three cases with each solution solving the Security Constrained Economic Dispatch problem. Each of these solution cases contains:

- A recommended set of zonal dispatch rates
- A list of exceptions to the dispatch rates for constraint control
- Individual resource dispatch rates
- Individual Resource Desired MW level

For the purpose of Real-time LMP, the Individual Resource dispatch rates are the \$/MW value from the resource offer curve corresponding to either the limited or unrestricted desired MW level. The limited desired MW value takes into account unit restrictions such as ramp rate limits, economic minimum, and economic maximum. In contrast, the unrestricted desired MW value ignores ramp rate limits.

UDS gathers transmission constraint information from the EMS and develops its dispatch solution based on using the most economic resources to control a given constraint. The optimization that takes place when the UDS executes ensures that the optimal dispatch solution is reached respecting all binding transmission constraints.

When the operator approves a recommended solution, the zonal dispatch rates and/or individual resource MWs are bridged to the EMS, where they are automatically sent out to resources or local control centers.

In addition to being used for economic dispatch, results of each approved solution are used as input to the Real-time LMP calculation. When the operator approves a recommended solution, the following data is sent to the Real-time LMP calculation:

- Individual Resource dispatch rates
- Resource specific Desired MW level (UDS Des MW)
- Binding transmission constraints

2.6 PJM State Estimator



The Real-time LMP calculation depends upon having a complete and consistent power flow solution as input. This input requirement can be achieved by using a state estimator. The state estimator is a standard power system operations tool whose purpose is to provide a base case power flow solution for input into other computer programs.

The state estimator uses actual operating conditions that exist on the power grid (as described by metered inputs) along with the fundamental power system equations to calculate the remaining flows and conditions that are not metered. Since the state estimator solution provides a complete and consistent model of actual operating conditions based upon observable (metered) input and an underlying mathematical model, it can be used to provide the basis for the Locational Marginal Price calculations.

The inputs to the state estimator are the available (metered) real-time measurements, the current status of equipment (lines, generators, transformers, etc.), and the bus load distribution factors.

This standard industry tool depends upon data redundancy and the underlying physical and mathematical relationships of the power system to provide a solution with less error than the original measurements. Therefore the state estimator can correct “bad data” and calculate missing data in the model to provide a consistent representation of existing network conditions.

The PJM state estimator is run on a thirty-second cycle and can provide the following inputs to the PJM LMP Model, on a five-minute basis:

- AC powerflow solution
- Actual generator MW output
- Bus loads
- Tie line flows
- MW losses by transmission zone
- Actual MW flow on any constrained transmission facility

2.7 Locational Pricing Algorithm (LPA) Preprocessor

Since the Real-time LMP calculation is based on actual resource output rather than a theoretical optimal dispatch, it is necessary to screen resources to determine if they are eligible to participate in the Real-time LMP calculation.

The LPA Preprocessor performs this screening function by analyzing the following to determine if a resource is following economic dispatch requests.



- Resource state estimated MWh output (aka Real-time MWh or SE MW)
- Resource offer price curves
- Economic dispatch rates
- Desired MW level for each resource that was specified by UDS

The program therefore acts as a real-time performance monitoring function for resources that have designated themselves as dispatchable.

Dispatchable resources whose actual MW output is 110% or less than the desired MW level are considered to be following the economic dispatch instructions and are therefore eligible to be passed through to the LPA as eligible resources. This evaluation includes any resources that are specifically requested by the UDS program to operate out of economic merit order dispatch in order to control a transmission constraint. These resources are designated as eligible to set LMP if they are on-line and following the dispatch instruction. When designated, an “eligible to set LMP” flag is set for each resource for each applicable 5-minute interval within an operating hour. The LPA Preprocessor also screens external bilateral transactions that are designated as dispatchable to determine if their offer data is consistent with current dispatch rates and if they are therefore eligible to set LMP.

Resources that are declared as must run and not following PJM’s dispatch, resources that are designated as ‘Fixed Gen’ in the eMKT system, and resources that are not following economic dispatch requests based on the criteria outlined above will not be eligible to set Real-time LMPs.

The offer price of eligible resources corresponds to a value derived from their applicable offer curve (or MW schedule for external bilateral transactions). The LPA Preprocessor calculates this Real-time offer value using the following criteria:

- If the resource’s state estimated MW value is less than or equal to the desired MW value, then the Real-time resource offer value is calculated by comparing the state estimated MW output to the resource’s offer curve.
- If the resource’s state estimated MW value is greater than the desired MW value, then the Real-time resource offer value is calculated as its dispatch rate.

The eligible resources are introduced to the LPA and are modeled at actual MW output with a small bandwidth to allow for solution tolerance. Resources that are not eligible to participate in Real-time LMP calculations are modeled as ineligible resources with their MW output fixed at the actual MW value from the state estimator solution.

Figure 2 below shows how the LPA Preprocessor determines the list of eligible units and transactions.

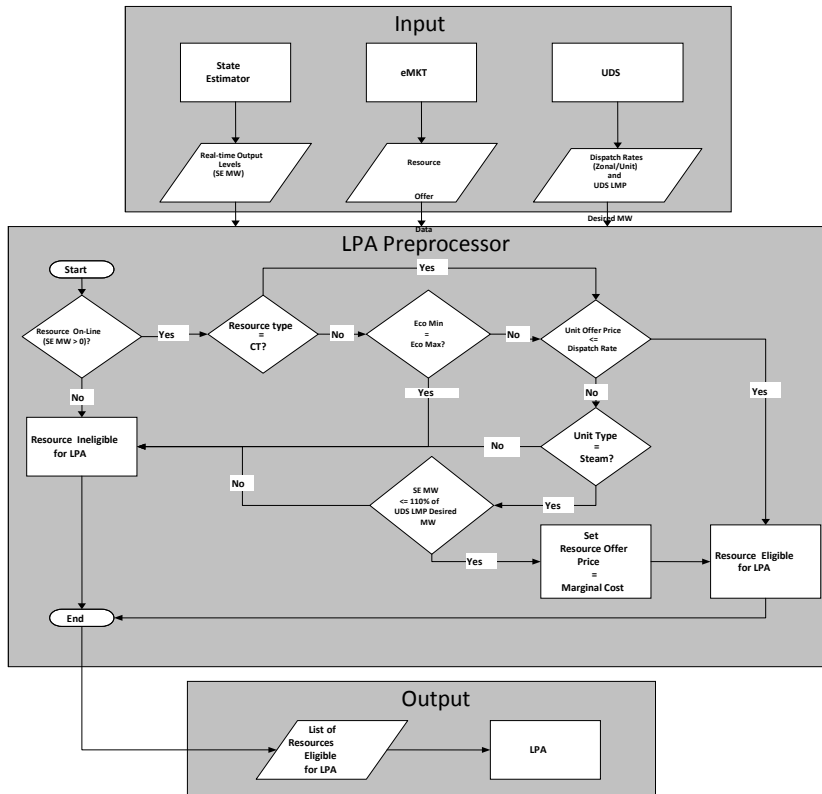


Figure 2



2.8 Locational Pricing Algorithm

The function of the Locational Pricing Algorithm (LPA) is to determine the Real-time LMP values on a five minute basis. The LPA calculates prices for each of the PJM nodes in the state estimator model and for interface busses used as a proxy for transfers to and from PJM and external control areas. The Real-time LMPs are defined as the cost to serve the next increment of load at each node bus location for the current system state estimated operating point, taking into account eligible resource real-time offer prices and the buses' location with respect to transmission limitations and incremental system losses.

The LPA is an incremental linear optimization program that is formulated at the current state estimated operating point. The objective is to minimize the cost function subject to the power balance constraint, generation MW bounds, transaction MW bounds, any transmission constraints that currently exist on the system and a normalized distribution of system losses to a network location.

Since the goal of the PJM LMP system is to calculate the Real-time LMP values based on actual system operating conditions, the state estimated powerflow solution is used as a starting point for the incremental linear programming formulation. This powerflow solution is then linearized in order to perform the LMP calculations. As outlined in previous sections, the set of eligible resources is determined by the LPA Preprocessor and is input to the LPA as a set of control variables. The set of eligible resources, P_i , are modeled in the formulation at the state estimated MW amount with a small bandwidth to allow for solution tolerance. The cost coefficients in the objective function for the eligible resources are set equal to the Real-time bid that is calculated by the LPA Preprocessor based on the state estimated MW level and the incremental offer (or bid) curve. These cost coefficients are assumed to have a constant slope.



The PJM incremental linear programming formulation is as follows:

Minimize:

$$Z = \sum C_i(\Delta P_i)$$

Subject to:

$$\sum_{i=1}^n \Delta P_i - Loss = 0 \quad (\text{power balance})$$

$$\sum_{i=1}^n A_{ij} (\Delta P_i - D_i^{Loss} \times Loss) \leq 0 \quad (\text{network constraints})$$

$$\Delta P_i^{\min} \leq \Delta P_i \leq \Delta P_i^{\max} \quad (\text{resource limits})$$

where:

ΔP_i - the change in rate of energy injection (+) or energy consumption (-) in MW for resource i.

$Loss$ - total system loss demand (in MW) as a function of location-specific injections and withdrawals

ΔP_i^{\max} - the upper MW bound for resource i

ΔP_i^{\min} - the lower MW bound for resource i

i - an index over the set of flexible resources

C_i - the calculated real-time price for resource i

A_{ij} - the sensitivities for resource bus i and active constraint j with respect to the reference bus

D_i^{loss} - normalized distribution of system losses to network location i.

The LMP values at each bus are by-products of the linear programming formulation that is listed above. The LMP value at a particular location is essentially the sum of the system marginal price of generation at the reference bus plus the marginal congestion price at the location associated with the various binding transmission constraints plus the marginal loss price at the location. The marginal values associated with various constraints in the optimization problem are called shadow prices. The shadow price of a constraint can be explained as the incremental change in value of the objective function for a unit change in the limit (right hand side) of the constraint. Therefore, an equation for computing LMPs can be expressed in terms of these shadow prices.

The LMP equation can be written as follows:

$$LMP_i = \lambda - \sum [A_{ik} (SP_k)] + \lambda \left(\frac{1}{Pf_i} - 1 \right)$$

where:

LMP_i = the Locational Marginal Price at bus i

λ = the system marginal price of generation at the reference bus

A_{jk} = the sensitivity for bus i on binding constraint k

SP_k = the shadow price of constraint k

Pf_i = the penalty factor for resource i. $Pf_i = \left(1 - \frac{\partial Loss}{\partial P_i} \right)^{-1}$

Determination of LMPs for De-Energized Busses

Due to equipment outages, the main transmission system may contain some de-energized busses for which LMPs cannot be directly calculated. It is necessary for settlement purposes that LMPs for these de-energized busses be established. The methodology for determining LMPs at de-energized busses is to assign to them the LMPs at their neighboring energized busses. The following criteria for a search is designed and implemented in the market clearing software.

Search rules:

1. Search at the same voltage level.
- Check whether any of the other busses belonging in the same voltage level as the de-energized bus is energized. If an energized bus is found, set the LMP of the de-



energized bus equal to the LMP of the energized bus. If a suitable replacement cannot be found, proceed to step 2.

2. Search at the same station.
 - Check whether there are any energized busses located at a voltage level different from the de-energized-bus voltage level but at the same station. If an energized bus is found, set the LMP of the de-energized bus equal to the LMP of the energized bus. If a suitable replacement cannot be found, proceed to step 3.
3. Search in the nearest neighboring stations.
 - Rank all the transmission lines out of the de-energized bus station in the descending order of their admittances.
 - Check whether there is any energized bus in the next station available in the rank. If one is found, set the LMP of the de-energized bus equal to the LMP at the energized bus.

If by searching all the neighboring stations no energized bus is found, the PJM Market Operator will be notified that a de-energized bus exists for which no suitable replacement could be found using the above steps and will be required to manually search for a suitable replacement.

Formatted: PJM_Normal, Left

2.9 PJM Real-time Locational Marginal Price Verification Procedure

PJM continually monitors the processes that are associated with the calculation of Real-time LMPs. In the event of a data input failure, program failure, or logging error, corrective actions may be taken to ensure that the resulting Real-time LMPs are as accurate as is reasonably obtainable.

- Data Input Failures (Stale cost data, stale dispatch rates, stale EMS data) or Program Failures (State Estimator failure, LPA Failure, Constraint logger failure) - Data input failures can occur when telecommunication problems exist either on the PJM computer network or on the data lines between PJM and PJM member companies. If failures occur within PJM's network, all possible steps will be taken to recover the original data for use in LMP calculation reruns. In the event of a program failure, an attempt will first be made to correct the reason for the failure and to recalculate LMP values for the affected intervals. If the failure cannot be corrected (due to a data input failure), and the original data cannot be recovered, PJM may utilize data from the best available alternate data sources including, but not limited to, backup systems, dispatcher logs, raw telemetry data, and member company data sources. In the event of a data input or program failure, LMP replacements will be performed as outlined below:
 - If the stale data or program failure exists for less than 6 intervals within the same hour then the affected intervals will be replaced with data from the last successful interval.
 - If the stale data or program failure exists for more than six intervals within the same hour then:



- If the hour is unconstrained, the hourly LMP will be replaced with the hourly integrated dispatch rate, or
- If the system is constrained, the LMP values will be recalculated using data from the best available sources.
- If the stale data or program failure exists for less than 6 intervals within the same hour but the previous hour had 12 failures then:
 - If the hour is unconstrained, the hourly LMP will be replaced with the hourly integrated dispatch rate, or
 - If the system is constrained, the LMP values will be recalculated using data from the best available sources.
- *Logging Errors (Transmission constraint logging, CT logging)* – The reference for logging times is the transmission dispatcher manual log. In the event of a logging error, LMP replacements will be performed as outlined below:
 - Transmission constraint or CT logs entered (or removed) with a delay of less than four intervals) – No recalculation of LMP is required.
 - Transmission constraint or CT logs entered (or removed) with a delay of four intervals or more) – The constraint and/or CT data will be corrected and LMP values will be recalculated.
 - Transmission constraint or CT logs entered incorrectly - The constraint and/or CT data will be corrected and LMP values will be recalculated.

Formatted: PJM Bullet 2, No bullets or numbering

Formatted: PJM Bullet 2, No bullets or numbering

Formatted: PJM Bullet 2, No bullets or numbering

2.10 Price-Bounding Violations

Under certain isolated system conditions the LPA itself may not be able to calculate real-time LMPs as accurately as others. For this reason PJM institutes a Price-Bounding Tolerance to establish a reasonable difference between dispatch rates and ex-post LMPs that when exceeded will result in disabling the posting of ex-post LMPs. The Price-Bounding Tolerance does not impact the LMP calculation itself as it is only used as a metric to determine the accuracy of the ex-post solution when considering the dispatch instructions sent out. The value of this tolerance is determined by PJM Market Operations staff as system conditions permit.

2.11 Calculation of Ramp Limited Desired MWh

Operating Reserve deviations to generators that are operating at PJM’s direction are based on a comparison of their Real-time desired MW with their Real-time MWh. For the purposes of settlement of Operating Reserve charges and credits, a Ramp-Limited Desired MW value will be



used to determine whether a unit is following PJM dispatch instructions as well as the actual quantity of deviations that will be calculated when a unit be determined to not be following dispatch instructions.

PJM will calculate a Ramp Limited Desired MW value for units where the economic minimum and economic maximum are at least as far apart in real-time as they are in Day-Ahead.

- Real Time Economic Minimum \leq 105% of Day-ahead Economic Minimum or Day-ahead Economic Minimum plus 5MW, whichever is greater.
- Real Time Economic Maximum \geq 95% Day-ahead Economic Maximum or Day-ahead Economic Maximum minus 5MW, whichever is lower.

PJM will determine a unit's Ramp-Limited Desired MW according to the following calculation:

$$\text{Ramp_Request}_t = \frac{(\text{UDStarget}_{t-1} - \text{AOutput}_{t-1})}{(\text{UDSLAtime}_{t-1})}$$
$$\text{RL_Desired}_t = \text{AOutput}_{t-1} + \left(\text{Ramp_Request}_t * \text{Case_Eff_time}_{t-1} \right)$$

where the variables are:

- UDStarget = UDS basepoint for the previous UDS case
- AOutput = Unit's output at case solution time
- UDSLAtime = UDS look ahead time
- Case_Eff_time = Time between base point changes
- RL_Desired = Ramp limited desired MW

UDS LMP Desired MWh is calculated by comparing the hourly integrated UDS LMP to the unit's bid curve to determine a corresponding MW value. This value is not ramp-limited.

In the event of technical difficulties where either a) UDS data does not exist or b) there is not a sufficient amount of data to calculate a reasonable Ramp Limited Desired MW value, the UDS LMP Desired MW value will be used.



PJM utilizes the Ramp-Limited Desired MW value to determine whether a unit is following PJM dispatch instructions. PJM will calculate two values, for a generation resource that is operating at PJM's direction:

- the MW off dispatch - is a defined term that is the lesser of the difference between the actual output of a unit in MW and the UDS Basepoint, or the difference between the actual output of a unit in MW and its Ramp-Limited Desired MW.
- % off dispatch.

PJM will use the lesser of the difference between the actual output and the desired dispatch point, or the actual output and Ramp-Limited Desired MW value. The % off dispatch and MW off dispatch will then be calculated as time-weighted averages of the values calculated with each dispatch solution over the course of an hour.

Pool-scheduled and dispatchable self-scheduled resources operating above economic minimum will then be considered to be following dispatch if:

- (a) actual output is between their Ramp-Limited Desired MW value and desired dispatch point,
 - (b) % off dispatch is less than or equal to 10, or
 - (c) hourly integrated Real-time MWh are within five percent (5%) or 5 MW (whichever is greater) of the hourly integrated Ramp-Limited Desired MW.
- Dispatchable pool-scheduled and self-scheduled generation resources that follow dispatch won't be assessed Balancing Operating Reserve deviations, and those that do not follow dispatch will be assessed Balancing Operating Reserve deviations based on $|\text{hourly integrated Real-time MWh} - \text{hourly integrated Ramp Limited Desired MW}|$, pursuant to the rules as defined in PJM Manual M28. The rules provide that Ramp-Limited Desired MW value must be used to determine real-time deviations from day-ahead schedules for generation resources. (See "Operating Reserve" section of PJM Manual M28 for a detailed description of the calculation of generator deviation charges).

2.12 Using and Calculating Locational Marginal Prices

LMPs are used in the PJM Energy Market accounting to calculate charges or credits for many of the market services, including:

- *Spot Market Energy* — LMPs are used to calculate the charges for Spot Market Energy purchases and the credits for Spot Market Energy deliveries. (See "Spot Market Energy Accounting" section of PJM Manual M28 for a detailed description of these calculations).



- *Operating Reserve* — LMPs, along with other components, are used to determine whether providers of Operating Reserve are properly compensated for their costs. (See “Operating Reserve Accounting” section of PJM Manual M28 for a detailed description of this calculation).
- *Transmission Congestion* — Congestion price components of LMPs are used in the calculation of Transmission Congestion Charges and to determine the value of FTRs used in the calculation of Transmission Congestion Credits. (See “Transmission Congestion Accounting” section of PJM Manual M28 for a detailed description of this calculation).
- *Transmission Losses* — Loss price components of LMPs are used to determine the charges for transmission losses. (See “Transmission Losses Accounting” section of PJM Manual M28 for a detailed description of this calculation).
- *Emergency Energy* — LMPs are used to calculate the charges and credits for Emergency purchases and sales between PJM and other Control Areas. (See “Emergency Energy Accounting” section of PJM Manual M28 for a detailed description of this calculation).
- *PJM Load Response Programs* – LMPs are used to calculate charges and credits for the PJM Load Response Programs (see “Section 9: PJM Load Response Programs Accounting” of PJM Manual M28 for a detailed description of this calculation).
- *Metering Reconciliation* — Weighted average LMPs are used to calculate monthly meter error correction charges between PJM Members and between Control Areas. (See “Metering Reconciliation Accounting” section of PJM Manual M28 for a detailed description of this calculation).

In general, generators are paid based on the generator bus LMP and loads are charged based on the load bus LMP. Transmission Customers or Energy Market Buyers are charged for congestion on transactions based on the differential in source and sink LMPs. LMPs are calculated on a periodic basis throughout the Operating Day, nominally every five minutes. At the end of each hour, an average of the five-minute LMP values is computed. The resulting hourly LMPs are then used in the PJM Energy Market accounting, as described in the other sections of this manual.

PJM Actions:

- PJM determines which CT units can set LMP. A CT can set LMP if it meets any of the following criteria:



- The CT is on for economic reasons, the CT bid price is less than or equal to the dispatch rate, and the state estimator MW output of the CT is greater than zero.
- The CT is logged on for transmission and a transmission constraint is logged (CTs logged as on for transmission when a constraint is not logged are treated as economic), the CT bid price is less than or equal to the dispatch rate, and the state estimator MW output of the CT is greater than zero.
- PJM determines which steam units can set LMP. A steam unit can set LMP if it meets the following criteria:
 - The steam unit is not on for transmission congestion and the bid price is less than or equal to the dispatch rate, and the state estimator MW value is less than or equal to 110% of the unit's desired MW value.
 - The steam unit is on for transmission congestion and a transmission constraint is logged, the bid price is less than or equal to the dispatch rate, and the state estimator MW value is less than or equal to 110% of the unit's desired MW value.
- PJM determines the pool transactions that can set LMP. A pool transaction can set LMP if the transaction bid price is less than or equal to the Dispatch Rate.

2.12.1 Day-ahead Settlement

- Day-ahead settlement is based on Day-ahead hourly LMPs. The components of Day-ahead hourly LMPs are the Day-ahead System Energy Price, Day-ahead Congestion Price, and the Day-ahead Loss Price. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.
- FTR holders receive congestion credits based on hourly day-ahead Congestion Price component of LMP values. Therefore, under two-settlement, congestion charges for the hour from both day-ahead and real-time markets are distributed to FTR holders based on target allocations, which are calculated as a function of day-ahead prices. Excess congestion charges are distributed according to the method described in Manual 28: Operating Agreement Accounting.
- Operating Reserves — there are separate operating reserve credit calculations for the Day-ahead Market and the Balancing market. This option preserves the incentive for demand and supply to bid into the Day-ahead Market based on their actual expectations and preserves the incentive for generation to follow real-time dispatch signals. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.

2.12.2 Balancing Settlement

- Balancing settlement is based on Real-time LMP values averaged over the hour. The components of Real-time hourly LMPs are the Real-time System Energy Price, Real-



time Congestion Price, and the Real-time Loss Price. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.

- FTRs do not apply to balancing settlement. FTRs apply to the day-ahead settlement only, because of the market revenue adequacy issue. PJM cannot provide financial hedging in both the day-ahead and the balance markets, which in effect is selling the service twice.

2.13 Balancing Operating Reserve Cost Analysis

Accounting for Operating Reserve is performed on a daily basis. A pool-scheduled resource of a PJM Member is eligible to receive credits for providing Operating Reserve in the day-ahead market and, provided that the resource was available for the entire time specified in its offer data, in the balancing market. The total resource offer amount for generation, including startup and no-load costs as applicable, is compared to its total energy market value for specified operating period segments during the day (including any amounts credited for day-ahead scheduling reserve in excess of the day-ahead scheduling reserve offer, any amounts credited for synchronized reserve in excess of the synchronized reserve offer plus opportunity cost, and any amounts credited for resources providing reactive services). If the total value is less than the offer amount, the difference is credited to the PJM Member.

Credits are also provided for pool-scheduled energy transactions, for generating units operating as synchronous condensers (not for synchronized reserve nor for reactive services) at the direction of PJM, for cancellation of pool-scheduled resources, for units whose output is suspended or reduced due to a transmission constraint or other reliability reason, for units performing an annual black start test, and for units providing reactive services at the direction of PJM.

The offered price for pool-scheduled resources will be capped for the entire operating day in the event either of the following conditions exists:

- The generation resource is identified in the day-ahead schedule to be dispatched out of economic merit order to control an identified transmission constraint.
- The generation resource is dispatched to provide quick start reserve for reliability.

In the event one of the above conditions exists, the offer prices will be capped at one of the following three levels, as specified in advance by the resource owner:

- The weighted average real-time Locational Marginal Price at the generation bus during all hours over the past six months in which the resource was dispatched in economic merit order above minimum.
- The incremental operating cost of the generation resource as determined in the PJM Cost Development Guideline Manual plus a 10% adder.



- An amount negotiated between PJM and the Market Seller in the event the generation resource cannot recover costs with either of the first two methods above.

The total cost of Day-ahead Operating Reserve for the Operating Day is allocated and charged to PJM Members in proportion to their total cleared day-ahead demand and decrement bids plus their cleared day-ahead exports for that Operating Day. The total cost of Balancing Operating Reserve for the Operating Day is allocated and charged to PJM Members in proportion to their locational real-time deviations from day-ahead schedules and generating resource deviations during that Operating Day, or to PJM Members in proportion to their real-time load plus exports during that Operating day for generator credits provided for reliability. In order to determine the reason why the Operating Reserve credit has been earned so that the charges related can be properly allocated, PJM conducts a Balancing Operating Reserve Cost Analysis (BORCA). PJM also calculates a Regional Balancing Operating Reserve rate for the costs of Operating Reserves that result from actions to control transmission constraints that are solely within pre-defined regions in the RTO. Additional costs of Operating Reserves that result from actions to control transmission constraints that benefit the entire RTO will continue to be allocated equally to deviations across the entire RTO. A detailed description of the Regional Balancing Operating Reserve Cost Analysis (BORCA) analysis can be found in M11. The total cost of synchronous condenser payments (other than that for synchronized reserve or reactive services) for the Operating Day is allocated and charged to PJM Members in proportion to their total load plus their exports during that Operating Day. The total cost of Reactive Services for the Operating Day is allocated and charged to PJM Members in proportion to their total load in the applicable transmission zone.

The purpose of the Balancing Operating Reserve Cost Analysis is to separate those Balancing Operating Reserve charges to be allocated to deviations between Day-ahead schedules and Real-time quantities from those that should be allocated to real-time load and exports. The key factor in separating the allocation is the determination of the particular units by which operating reserve credits were earned, and the units for which those credits should be allocated to deviations as opposed to those units for which those credits should be allocated to load and exports. This cost determination will occur in two stages: those units called on during the Reliability Analysis, and those units called on to operate during the Operating Day. In both cases, the proposed changes establish clear, definitive, and objective criteria that will be applied to such units to determine the reason Balancing Operating Reserve credits were earned.

Resources scheduled by PJM during its reliability analysis for an Operating Day, the associated Balancing Operating Reserve charges are allocated based on the reason the resource was scheduled.

- When a resource is scheduled by PJM during its reliability analysis if the resource is committed to operate in real-time to augment the physical resources committed in the Day-ahead Energy Market to meet the forecasted real-time load plus the Operating



Reserve Requirement, then in such cases, Balancing Operating Reserve charges will be allocated to real-time deviations from day-ahead schedules.

- If however, a resource is scheduled by PJM during its reliability analysis not to account for anticipated deviations between day-ahead schedules and real time conditions but instead to provide additional reliability margin, Balancing Operating Reserve charges must be allocated to real-time load plus exports.
- Balancing Operating Reserve credits earned by units called on by PJM to operate during the Operating Day for which the LMP at the unit's bus does not meet or exceed the unit's applicable offer (cost or price) for at least four, five-minute intervals of at least one clock hour during which the unit was running at PJM's direction will be allocated according to ratio share of load plus exports.
- Balancing Operating Reserve credits earned by all other units operating at PJM's direction in real-time will be allocated according to deviations between Day-ahead schedules and Real-time quantities. The logic behind this distinction is that units called on in real-time for which LMP exceeds their offer for a significant number of intervals while they are running are necessary to meet load requirements respecting active transmission constraints.
- Units called on at PJM's direction in real time for which the LMP does not exceed the unit's offer were not needed and were therefore operating in order to ensure reliability is maintained as opposed to account for differences between day-ahead schedules and real-time system conditions.

PJM further collects Balancing Operating Reserve credits that are accrued to resources operating to manage local transmission constraints. In order to appropriately collect the costs of Balancing Operating Reserve for local constraints within the pre-determined regions where the constraints existed, PJM calculates Regional Balancing Operating Reserve adders.

PJM calculates Regional Balancing Operating Reserve adders for the following Regions within the PJM RTO

- Western Region of PJM RTO, comprised of the AEP, APS, ATSI, ComEd, Duquesne, Dayton and DEOK Zones and
- Eastern Region of PJM RTO made of the AEC, BGE, Dominion, PENELEC, PEPCO, ME, PPL, JCPL, PECO, DPL, PSEG and RE Zones.

Balancing Operating Reserve credits that are accrued to resources operating to control transmission constraints that benefit the entire RTO are charged as an RTO Balancing Operating Reserve rate. (See "Operating Reserve Accounting" section of PJM Manual M28 for a detailed description of the calculation of allocation charges).

2.13.1 Maximum Emergency Generation in Day-ahead Market



- If the day-ahead demand bid MW cannot be satisfied with all available generation at its economic maximum MW limit, the program shall issue a Maximum Generation Warning message due to a shortage of economic generation in the Day-ahead Market. The program shall then perform the following steps to achieve power balance:
- Increase all on-line generation up to its maximum emergency MW limit. (Increase generator MW proportionately by ratio of economic maximum, if power balance is achieved prior to reaching maximum limits). Set LMP values equal to the highest offer of all on-line generation.
- Load off-line generation that is designated as available only for maximum generation emergency conditions, as required. The order of loading is based on economic offer data. Set LMP values equal to the highest offer of all on-line generation.
- If generation is still not enough to achieve power balance after Step 2, drop any remaining price-sensitive demand to zero MW. Set LMP values equal to the highest price-sensitive demand bid that was cut in this step. If no price-sensitive demand was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation (resulting from Step 2).
- If power balance is not achieved after step 3, reduce all load proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, the price from Step 3, or the bid cap (presently \$1000/ MWh), whichever is higher.

2.13.2 Minimum Capacity Emergency in Day-ahead Market

- If the day-ahead demand bid MW is less than the total generation MW with all possible generation off and with all remaining generation at their economic minimum MW limit, the program shall issue a Minimum Generation Warning message due to an excess of economic generation in the Day-ahead Market. The program shall then perform the following steps to achieve power balance.
- Reduce all on-line generation down to its minimum emergency MW limit. (Reduce generator MW proportionately, by ratio of economic minimum, if power balance is achieved prior to reaching minimum limits). Set LMP values equal to the lower of zero or to the lowest offer price of all on-line generation.
- Set LMP values to zero. Reduce all on-line generation below emergency minimum proportionately (by ratio of emergency minimum) to achieve power balance.



Section 3: Overview of the PJM Regulation Market

Welcome to the *Overview of the PJM Regulation Market* section of the PJM Manual for **Energy & Ancillary Services Market Operations**. In this section you will find the following information:

- An overview description of the PJM Regulation Market (see “Overview of PJM Regulation Market”).
- A list of the PJM Regulation Market Business Rules (see “PJM Regulation Market Business Rules”).

3.1 Overview of the PJM Regulation Market

The PJM Regulation Market provides PJM participants with a market-based system for the purchase and sale of the Regulation ancillary service. Resource owners submit specific offers to provide Regulation, and PJM utilizes these offers together with energy offers and resource schedules from the eMKT System, as input data to the Synchronized Reserve and Regulation Optimizer (SPREGO). SPREGO then optimizes the RTO dispatch profile and forecasts LMPs to calculate an hourly Regulation Market Clearing Price (RMCP). This clearing price is then used to determine the credits awarded to providers and charges allocated to purchasers of the Regulation service.

PJM uses resource schedules and regulation and energy offers from the eMKT System as input data to the Synchronized Reserve and Regulation Optimizer (SPREGO) to provide the lowest cost alternative for the procurement of Ancillary Services and energy for each hour of the operating day. The lowest cost alternative for these services is achieved through a simultaneous co-optimization of Regulation, Synchronized Reserve, and energy. Within the co-optimization, an RTO dispatch profile is forecasted along with LMPs for the market hour and adjacent hours. Using the dispatch profile and forecasted LMPs, an opportunity cost is estimated for each resource that is eligible to provide regulation. The estimated opportunity cost for demand resources will be zero. The estimated opportunity cost is then added to the regulation offer price to create the merit order price. All available regulating resources are then ranked in ascending order of their merit order prices, and the lowest cost set of resources necessary to simultaneously meet the PJM Regulation Requirement, PJM Synchronized Reserve Requirement, and provide energy that hour is determined. The highest merit order price associated with this lowest cost set of resources awarded regulation becomes the RMCP for that hour of the operating day. Resource owners may self-schedule Regulation on any qualified resource, and the merit order price for any self-scheduled Regulation resource is set to zero.

In the after-the-fact settlement, any resources self-scheduled to provide Regulation are compensated at the hourly RMCP. Any resources selected by PJM to provide Regulation are



compensated at the higher of the hourly RMCP or their real-time opportunity cost plus their Regulation offer price. LSEs required to purchase Regulation are charged the hourly RMCP plus their percentage share of opportunity cost credits.

3.2 PJM Regulation Market Business Rules

3.2.1 Regulation Market Eligibility

- Regulation offers may be submitted only for those resources electrically within the PJM RTO.
- The following resources criteria must be met:
 - Generation resources must have a governor capable of AGC control.
 - Resources must be able to receive an AGC signal.
 - Resources must demonstrate minimum performance standards, as set forth in the PJM Manual 12: Balancing Operations, Section 4: Providing Ancillary Services.
 - New resources must pass an initial performance test (minimum 75% compliance required). PJM will rely on owner's data for initial qualification. Resources qualified as of June 1, 2000 are grandfathered.
 - Resources must exhibit satisfactory performance on dynamic evaluations.
 - Resources MW output must be telemetered to the PJM control center in a manner determined to be acceptable by PJM.
 - Generation resources must be able to provide 0.1 MW of Regulation Capability in order to participate in the Regulation Market. Demand Resources must be able to provide 0.1 MW of Regulation Capability in order to participate in the Regulation Market.
 - Demand Resources must complete initial and continuing training on Regulation and Synchronized Reserve Market as documented in Manual 40: Certification and Training Requirements, Section 2.6: Training Requirements for Demand Response Resources Supplying Regulation and Synchronized Reserve.
- The following information must be supplied through the eMKT System:

Formatted: PJM Bullet 2, No bullets or numbering



- Resource Regulating Status (available, unavailable, self-scheduled)
- Regulation Capability (above and below regulation midpoint, MW)
- Regulation Maximum and Minimum values, considering any necessary offsets (MW)
- Cost-Based Regulation Offer (\$/MWh). This value will be validated using the unit-specific operating parameters submitted with the regulation offer and the applicable \$12/MWh regulation margin adder.
- Price-Based Regulation Offer (\$/MWh, optional): This value is capped at \$100/MWh, and its submission is optional on the part of the market participant.

Formatted: PJM Bullet 2, No bullets or numbering

In addition to the cost-based regulation offer price, each market participant may also submit additional information to support the cost-based offer price. Using the calculations in **Manual M-15: Cost Development Guidelines**, PJM will validate the cost-based regulation offer price to ensure that it does not exceed actual regulating cost as determined by this manual, plus the applicable regulation margin adder. Any cost-based offer prices that exceed this value will be rejected by the eMKT System. An example of this calculation is available on the pj m website at <http://www.pjm.com/markets-and-operations/ancillary-services/mkt-based-regulation.aspx>.

If a market participant does not submit a cost-based regulation offer price they will not be permitted to participate in the PJM Regulation Market until such offer has been validated. Any participants that do not submit any of the supporting parameters below will have their cost-based regulation offer price capped at the margin adder of \$12/MWh.

The following optional parameters may be submitted in the eMKT System to support the cost-based regulation offer price. If any of these parameters are not submitted they will default to zero.

- **Heat Rate @ EcoMax [BTU/kWh]:** The heat rate at the default economic maximum for a resource. The economic maximum that will correspond to this rate value will be the default economic maximum that is shown on both the Daily Regulation Offers and Unit Details pages.
- **Heat Rate @ RegMin [BTU/kWh]:** The heat rate at the default regulation minimum for a resource. The regulation minimum that will correspond to this rate value will be the default regulation minimum that is shown on both the Daily Regulation Offers and Unit Details pages.
- **VOM Rate [\$/MWh of Regulation]:** The increase in VOM resulting from operating the regulating resource at a higher heat rate than is otherwise economic for the purpose of providing regulation.



- **Fuel Cost [\$/MBTU]:** The fixed fuel costs of the resource. This value will be used to determine the heat rate adjustments during steady-state and non steady-state operation for the purpose of providing regulation.

3.2.2 Regulation Market Data Timeline

Cost-based and Price-Based Regulation Offer(s) and any applicable cost information must be supplied prior to 6:00 p.m. day-ahead and is applicable for the entire 24-hour period for which it is submitted. Resource Regulating Status, Regulation Capability, and Regulation Maximum and Regulation Minimum information may be submitted or changed up until sixty (60) minutes prior to the beginning of the operating hour, at which time the Regulation market closes. In the event that the Regulation Maximum and Regulation Minimum limits are not the most restrictive for a given resource (i.e. the Regulation Maximum the lowest of all the high limits and the Regulation Minimum the highest of all the low limits), the regulation software will utilize the most restrictive minimum and maximum of all applicable limits for real time.

- Should a unit wish not to participate in the regulation market in any given hour on the operating day, the following update should be made at least 60 minutes prior to the operating hour in the Regulation Updates screens of the eMKT System:
 - Set Offer MW to zero
 - Set Available status to Not Available.
- Should a unit's regulation operating parameters change after the regulation market closes for an hour, the following changes may be made through direct communication with the PJM Scheduling Coordinator.
 - Resource Regulating Status
 - Available to unavailable
 - Self-scheduled to unavailable
 - High Regulation Limit may be decreased but not increased and Low Regulation Limit may be increased but not decreased.
 - Regulating capability may be decreased but not increased.
 - Regulation Maximum capability may be decreased but not increased and Regulation Minimum capability may be increased but not decreased.
 - Any resource that is unavailable for energy when the Regulation market closes and becomes available during the operating hour may also be made available or self-scheduled for regulation. Any associated regulation offer

Formatted: PJM Bullet 2, No bullets or numbering

Formatted: PJM Bullet 2, No bullets or numbering



information may be changed for such resources, since none was considered in the calculation of RMCP.

- Resources that are self-scheduled for energy but do not have an available bandwidth above the self-scheduled value and below the applicable maximum greater than or equal to twice the regulation offer cannot be evaluated for the full amount of the offer. Such resources will be evaluated for regulating capability equal to half the bandwidth available.

3.2.3 Regulation Bilateral Transactions

- Bilateral regulation transactions may be reported to PJM. Such reported bilateral regulation transactions must be for the physical transfer of regulation and must be reported by the buyer and subsequently confirmed by the seller through the eMKT System no later than 1600 the day after the transaction starts. Bilateral transactions that have been reported and confirmed may not be changed; they must be deleted and re-reported. Deletion of a reported bilateral transaction is interpreted as a change in the end time of the transaction to the current hour, unless the transaction has not yet started.
- The buyer on the transaction submits the MW amount, the seller, and the start and end time of the transaction via the eMKT System. The seller confirms the transaction via the eMKT System by 1600 the day after the start date of the bilateral transaction.
- Payments and related charges associated with the bilateral regulation transactions reported to PJM shall be arranged between the parties to the bilateral contract.
- A buyer under a bilateral regulation contract reported to PJM agrees that it guarantees and indemnifies PJM, PJM Settlement, and the market participants for the costs of any purchases by the seller in the Regulation Market, as determined by PJM, to supply the reported bilateral transaction and for which payment is not made to PJM Settlement by the seller.
- Upon any default in obligations to PJM or PJM Settlement by a Market Participant, PJM shall not accept any new bilateral reporting by the Market Participant and shall terminate all of the market participant's reporting of eMarkets schedules associated with its bilateral regulation transactions previously reported to PJM for all days where delivery had not yet occurred.

3.2.4 Regulation Requirement Determination

- The total PJM Regulation Requirement for the PJM RTO is determined in whole MW for the on-peak (0500 – 2359) and off-peak (0000 – 0459) periods of day.



- The PJM RTO on-peak Regulation Requirement is equal to 1% of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1% of the forecast valley load for the PJM RTO for the day.
- The requirement percentage may be adjusted by the PJM Interconnection, if the adjustment is consistent with the maintenance of NERC control standards.

3.2.5 Regulation Obligation Fulfillment

- LSEs may fulfill their regulation obligations by:
- Self-scheduling the entity's own resources;
- Entering contractual arrangements with other market participants; or
- Purchasing regulation from the regulation market.

3.2.6 Regulation Offer Period

- Resource owners wishing to sell regulation service must at least supply a cost-based regulation offer price by 6:00 p.m. the day prior to operation, and the remainder of the necessary data prior to Regulation market closing as stated above in the Regulation Market Date Timeline section.
- Regulation offers are locked as of 6:00 p.m. the day prior to operation. The Markets Database is generally unavailable for entry between 12 noon and 4:00 p.m. the day prior to operation while the Day-ahead market is being cleared. All resources listed as available for regulation with no offer price have their offer prices set to zero.

3.2.7 Regulation Market Clearing

- PJM clears the regulation market simultaneously with the synchronized reserve market, and posts the results no later than 30 minutes prior to the start of the operating hour.
- PJM utilizes the Three Pivotal Supplier (TPS) Test in the regulation market to mitigate market power as detailed in section 3.2.2A.1 of the PJM Tariff. Each supplier, from 1 to n , is ranked from the largest to the smallest offered MW of eligible regulation supply in each hour. Suppliers are then tested in order, starting with the three largest suppliers. In each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the regulation requirement for the hour (D). Where j defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with $j=3$). Equation 0-1 shows the formula for the residual supply index for three pivotal suppliers (RSI3):

Equation 0-1 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^n S_i - \sum_{i=1}^2 S_i - S_j}{D}$$

Where $j=3$, if $RSI3_j$ is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a supplier j result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test. Any resource owner that fails the TPS Test will be offer-capped.

- Regulating resources are offer-capped at the lesser of their cost-based or market-based regulation offer price.
- An offer-capped resource will only be offer-capped for a single hour at a time as the TPS Test is rerun for each hour of the day.
- Resource merit order price (\$/MWh) = Resource regulation offer + estimated resource opportunity cost per MWh of capability
- Opportunity cost for Demand Resources will be zero.
- Demand Resources will be limited to providing 25% of the regulation requirement.
- Estimated resource opportunity cost is calculated as follows:
 - The Synchronized Reserve and Regulation Optimizer (SPREGO) optimizes resource energy schedules and forecasts LMPs for the operating hour while respecting appropriate transmission constraints and Ancillary Service requirements..
 - SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the “lost opportunity cost energy schedule”), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation. Regulation opportunity cost is divided into three components.
 - The lost opportunity cost incurred in the shoulder hour preceding the initial regulating hour while the unit moves uneconomically into its regulating band to comply with the next hour’s regulation assignment.

Formatted: PJM Bullet 2, No bullets or numbering



- o The lost opportunity cost incurred in the actual regulating hour from reducing or raising the unit's output uneconomically for the purpose of providing regulation.
- o The lost opportunity cost incurred in the shoulder hour following the final hour of the regulation assignment while the unit moves from its uneconomic regulation set point back to its economic set point.
- o The approximate formula for the lost opportunity incurred during the shoulder hours can be defined as:

$|LMP_{SH} - ED| * GENOFF * TIME$, where:

- a. LMP_{SH} is the forecasted shoulder hour LMP at the generator bus,
- b. ED is the price from the lost opportunity cost energy schedule associated with the setpoint the resource must maintain to provide its full amount of regulation, and
- c. GENOFF is the MW deviation between economic dispatch and the regulation setpoint.
- d. TIME is the percentage of the hour it would take the unit to reduce GENOFF MWs using the applicable bid-in ramp rate.

- o The approximate formula for the lost opportunity cost incurred during the regulating hour is:

$|LMP - ED| * GENOFF$, where:

- a. LMP is the forecasted hourly LMP at the generator bus,
- b. ED is the price from the lost opportunity cost energy schedule associated with the setpoint the resource must maintain to provide its full amount of regulation, and
- c. GENOFF is the MW deviation between economic dispatch and the regulation setpoint.

Both lost opportunity cost calculations are defined simplistically for the purpose of the manual. The actual calculations are integrations that may be visualized as the area on a graph enclosed by the lost opportunity cost energy schedule, the points on that curve corresponding to the resource's

Formatted: PJM Bullet 2, No bullets or numbering



desired economic dispatch and the setpoint necessary to provide the full amount of regulation, and the LMP.

SPREGO ranks all available regulating resources in ascending merit order price, and simultaneously determines the least expensive set of resources necessary to provide energy, regulation and synchronized reserve for the operating hour taking into account any resources self-scheduled to provide any of these services. Should the SPREGO application be unable to fulfill both the Regulation and Synchronized Reserve requirements, regulation receives the higher priority.

PJM may call on resources not otherwise scheduled to run in order to provide regulation, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. If a resource is called on by PJM for the purpose of providing regulation, the resource is guaranteed recovery of Regulation lost opportunity costs as well as start-up, no-load, and energy costs. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details. Energy resources that are self-scheduled to provide energy and do not supply an energy bid have no opportunity cost associated with providing regulation.

- The highest merit order price becomes the Regulation Market Clearing Price for that hour.
- The hourly RMCPs are posted in the eMKT user interface public view. RMCP and other billing determinant information is also available on the PJM website at <http://www.pjm.com/markets-and-operations/market-settlements/preliminary-billing-reports.aspx>
- If no Regulation Market Results are posted to the eMKT MUI for an hour, PJM will continue the current assignments, as needed, into the un-posted hour and the RMCP from the previous hour will be used for settlement.

3.2.8 Hydro Units

- Since hydro units operate on a schedule and do not have an energy bid, opportunity cost for these units is calculated as follows:
- The formula is the same as the Regulation Market Clearing Section above, except the ED value is an average of the LMP at the hydro unit bus for the appropriate on-peak (0700 - 2259) or off-peak (0000 – 0659, 2300 - 2359) period, excluding those hours during which all available units at the hydro plant were operating. If this average LMP value is higher than the actual LMP at the generator bus, the opportunity cost is zero. Day-ahead LMPs are used for the purpose of estimating opportunity costs for hydro units, and actual LMPs are used in the after-the-fact settlement.



- If a hydro unit is brought on out of schedule to provide regulation, the opportunity cost is equal to the average LMP (calculated as stated above) minus the actual LMP at the generator bus. If the actual LMP is higher than the average, the opportunity cost is zero.
- During those hours when a hydro unit is in spill, the ED value is set to zero such that the opportunity cost is based on the full value of LMP. During the operating day, the operating company is responsible for communicating this condition to the PJM Scheduling Coordinator, and indicating this condition on the Regulation Updates page of the eMKT System.
- When determined to be economically beneficial, PJM maintains the authority to adjust hydro unit schedules for those units scheduled by the owner if the owner has also submitted a regulation offer for those units and made the units available for regulation.
- An example of Regulation Hydro Lost Opportunity Cost Calculations can be found on the PJM website at <http://www.pjm.com/markets-and-operations/ancillary-services/mkt-based-regulation.aspx>

3.2.9 Regulation Market Operations

- The PJM Operator maintains total Regulation Zonal capabilities within a +/- 2%, but no less than +/- 15MW bandwidth around the RTO Regulation Requirement.
- The PJM Operator periodically evaluates the set of resources providing regulation, and makes any adjustments to regulation assignments deemed necessary and appropriate to minimize the overall cost of regulation.
- In the event of a regulation excess, the PJM dispatcher deselects resources beginning with the highest cost resource currently providing regulation and moving downward.
- In the event of a regulation deficiency, the PJM dispatcher selects resources to provide regulation beginning with the lowest cost resource currently not providing regulation and moving upward.
- The RMCP does not change based upon regulating resource adjustments made in real time. Any opportunity costs that exceed the RMCP are credited after the fact on a resource-specific basis.
- The PJM Energy Management System (EMS) sends one Control Area Regulation signal to each Local Control Center (LCC), as well as signals to individual resources or plants as requested by the owner.
- The PJM Operator communicates any change in resource regulating assignments to individual Local Control Centers. Company total in-service regulating capabilities are then telemetered back to the PJM EMS via the PJM data link.



- Resource regulation assignment changes during transitions between on-peak and off-peak periods begin 30 minutes prior to the new period, and are completed no later than 30 minutes after the period begins.

3.2.10 Settlements

- Please refer to Manual 28: Operating Agreement Accounting, Section 4: Regulation Accounting for settlement details.
- Regulation settlement is a zero-sum calculation based on the regulation provided to the market by generation owners and purchased from the market by LSEs.
- Opportunity cost is calculated as shown above in Market Clearing using actual integrated LMPs as opposed to that which was forecasted. PJM then adjusts the opportunity cost calculated for each resource based on the actual hourly integrated value of the real-time PJM regulation signal to account for the fact that the resource may have been held above or below its regulation setpoint for greater than half the hour.
- Energy resources that are self-scheduled to provide energy and do not supply an energy bid are not eligible to collect opportunity cost credits. These resources will receive credit equal to the RMCP times the amount of regulation self-scheduled on or assigned to them.



Section 4: Overview of the PJM Synchronized Reserve Market

Welcome to the *Overview of the PJM Synchronized Reserve Market* section of the PJM Manual for *Energy & Ancillary Services Market Operations*. In this section, you will find the following information:

- An overview description of the PJM Synchronized Reserve Market (see “*Overview of PJM Synchronized Reserve Market*”).
- A list of the PJM Synchronized Reserve Market Business Rules (see “*PJM Synchronized Reserve Market Business Rules*”).

4.1 Overview of the PJM Synchronized Reserve Market

The PJM Synchronized Reserve Market provides PJM participants with a market-based system for the purchase and sale of the Synchronized Reserve ancillary service. Resource owners submit resource-specific offers to provide Synchronized Reserve, and PJM utilizes these offers together with energy offers and resource schedules from the eMKT System, as input data to the Synchronized Reserve and Regulation Optimizer (SPREGO). SPREGO then optimizes the RTO dispatch profile and forecasts LMPs to calculate an hourly Synchronized Reserve Market Clearing Price (SRMCP). This clearing price is then used to determine the credits awarded to providers and charges allocated to purchasers of the Synchronized Reserve service.

PJM uses forecasted LMPs and resource schedules from the Synchronized Reserve and Regulation Optimizer (SPREGO) to estimate the amount of incidental Synchronized Reserve present on the PJM system due to economic dispatch and this capability is designated as Tier 1. Tier 1 is provided by any resource that is on line, following economic dispatch, and capable of increasing its output within ten (10) minutes following a call for Synchronized Reserve. If the amount of Tier 1 estimated for a given hour is insufficient to meet the PJM Synchronized Reserve Requirement, PJM must assign resources to operate at a point that deviates from economic dispatch in order to provide the remainder of the requirement. The extra capacity that must be committed is designated Tier 2. The acquisition of Tier 2 reserves is performed jointly with regulation and energy through a simultaneous co-optimization that provides the lowest cost alternative for the procurement of Ancillary Services and energy for that hour of the operating day. Within the co-optimization, an RTO dispatch profile is forecasted along with LMPs for that hour. Using the dispatch profile and forecasted LMPs, an opportunity cost (including energy usage) is estimated for each resource that is eligible to provide Tier 2 synchronized reserve. Demand resources have an estimated opportunity cost of zero. This estimated opportunity cost is then added to the synchronized reserve offer price to create the merit order price. All available Tier 2 synchronized reserve resources are then ranked in ascending order of their merit



order prices, and the lowest cost set of resources necessary to simultaneously meet the PJM Synchronized Reserve Requirement, PJM Regulation Requirement, and provide energy that hour is determined. The highest merit order price associated with this lowest cost set of resources awarded Tier 2 synchronized reserve becomes the SRMCP for that hour of the operating day. Resource owners may self-schedule Synchronized Reserve on any qualified resource, and the merit order price for any self-scheduled Synchronized Reserve resource is set to zero. PJM simultaneously optimizes energy, Regulation and Synchronized Reserve, and assigns both Regulation and Synchronized Reserve to the most cost-effective set of resources each hour of the operating day.

In the after-the-fact settlement, any resources self-scheduled to provide Synchronized Reserve are compensated at the hourly SRMCP. Any pool-scheduled resources selected to provide Synchronized Reserve are compensated at the higher of the hourly SRMCP or their real-time opportunity cost plus their Synchronized Reserve offer price. LSEs required to purchase Synchronized Reserve are charged the hourly SRMCP plus their percentage share of opportunity cost credits and Tier 1 credits.

4.2 PJM Synchronized Reserve Market Business Rules

4.2.1 Synchronized Reserve Market Eligibility

- Synchronized Reserve offers may be submitted only for those resources located electrically within the Synchronized Reserve Zone.
- Resources participating in the synchronized reserve market are divided into two Tiers:
- **Tier 1** is comprised of all those resources on line following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event, or demand resources capable of reducing load within 10 minutes.
- **Tier 2** consists of:
 - that additional capacity that is synchronized to the grid and operating at a point that deviates from economic dispatch (including condensing mode) to provide additional spinning synchronized reserve not available from Tier 1 resources; and
 - dispatchable load resources that have controls in place to automatically drop load in response to a signal from PJM.
- All resources operating on the PJM system with the exception of those assigned as Tier 2 resources are by definition Tier 1 resources. Any resource capable of operating in condensing mode or willing to operate with an output less than that dictated by economic dispatch may participate as a Tier 2 resource. There is no qualification process for Tier 2

Formatted: PJM Bullet 2, No bullets or numbering



resources. However, consequences exist as described below for response by Tier 2 resources that are less than that which is committed.

- The following information must be supplied through the eMKT System:
 - Synchronized Reserve Ramp Rate for Tier 1 resources (MW/minute). A separate rate may be submitted for multiple segments of a resource's MW range, and these rates must be greater than or equal to the real-time economic ramp rate(s) submitted for the resource. Synchronized reserve ramp rates that exceed economic ramp rates must be justified via submission of actual data from past synchronized reserve events to the PJM Performance Compliance Department.
 - Synchronized reserve maximum for Tier 1 resources. This value represents the maximum MW output a resource can achieve in response to a synchronized reserve event. Synchronized reserve maximum must be greater than or equal to the economic maximum for the resource except for qualified resources that have been granted exception due to their physical limitation.
 - Generation resources must be able to provide 0.1 MW of Tier2 Synchronized Reserve Capability in order to participate in the Tier2 Synchronized Reserve Market. Demand Resources must be able to provide 0.1 MW of Tier2 Synchronized Reserve Capability in order to participate in the Tier2 Synchronized Reserve Market.
 - Synchronized Reserve Availability for Tier 2 resources. Resources may be made available, unavailable, or self-scheduled to provide Tier 2 synchronized reserve.
 - Synchronized Reserve Offer Quantity for Tier 2 resources (MW). This quantity is defined as the increase in output achievable by the resource in ten (10) minutes, or the load reduction achievable in ten (10) minutes.
 - Synchronized Offer Price for Tier 2 resources (\$/MWh). Synchronized Reserve Offer Prices will be capped at a maximum value of the resource's O&M cost (as determined by the Cost Development Task Force) plus \$7.50/MWh margin.
 - Energy use for condensing Tier 2 resources (MW). This is the amount of instantaneous energy a condensing resource consumes while operating in the condensing mode. The value submitted as part of the synchronized reserve offer must be less than or equal to the actual energy consumed as observed in real time.
 - Should a resource wish not to participant in the Synchronized Reserve market in any given hours on the operating day, the following update should

Formatted: PJM Bullet 2, No bullets or numbering



be made at least 60 minutes prior to the operating hour in the Synchronized Reserve Update screens of eMKT:

- Set Offer MW to zero
- Set Available status to Not Available.
- Condense to gen cost. This is the cost of transitioning a condenser to the generating mode. The value submitted for this cost must be less than or equal to the condensing start cost.
- Shutdown Costs. These are the costs a Demand Resource incurs when reducing load in response to a synchronized reserve event.
- Condense Startup Cost. This is the actual cost associated with getting a resource from a completely off-line state into the condensing mode including fuel, O&M, etc.
- Condense Hourly Cost. This is the hourly cost to condense is equal to the actual, variable O&M costs associated with operating a resource in the condensing mode, including any fuel costs. It does not include any estimate for energy consumed
- Condense Notification Time. The amount of advance notice, in hours, required to notify the operating company to prepare the resource to operate in synchronous condensing mode. The default value is 0 hours.
- Spin as Condenser. This is used to identify if a combustion turbine can be committed for synchronized reserve as a condenser.
- Tier 1 estimates for Demand Resources will equal zero.

4.2.3 Synchronized Reserve Requirement Determination

PJM will select resources in each Synchronized Reserve Zone hourly to provide synchronized reserve based on a co-optimization between energy, regulation and synchronized reserve. Assignments will be communicated to the resource owners/operators by eMKT or the appropriate dispatcher.

The RTO will be arranged into two (2) Synchronized Reserve Zones. All companies within PJM, excluding the SERC companies, are part of the ReliabilityFirst Corporation (RFC) reliability region and will thus be grouped together into a single synchronized reserve zone. The SERC companies are part of a separate reserve sharing agreement and therefore comprise a second synchronized reserve zone. The two (2) synchronized reserve zones contain the following control zones:

RFC Synchronized Reserve Zone:



- PJM Mid-Atlantic
- AP
- AEP
- ATSI
- Dayton
- Duquesne
- CE
- DEOK

Southern (Dominion) Synchronized Reserve Zone:

- Dominion
 - Total PJM Synchronized Reserve Requirement for each Synchronized Reserve Zone is determined in whole MW for each hour of the operating day.

Formatted: Indent: Left: 0.75"

The RFC Synchronized Reserve Zone Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. The requirement will be defined as the greater of the ReliabilityFirst Corporation (RFC) imposed minimum requirement or the largest contingency on the system.

The Southern Synchronized Reserve Zone Requirement is defined as the Dominion load ratio share of the largest system contingency within VACAR; minus the available 15 minute quick start capability within the Southern Synchronized Reserve Zone.

- North American Electric Reliability Council (NERC) standards may impose greater requirements for synchronized reserve following Disturbance Control Standard (DCS) violations. Any such impositions will be incorporated as an increase to the overall control zone synchronized reserve requirement.

Due to transmission security considerations on the PJM system, it is sometimes necessary to carry a minimum amount of synchronized reserve in specific sub-zones in PJM such that loading 100% synchronized reserve will not result in an overload of any of the PJM transfer interfaces. The Mid-Atlantic Sub-Zone is defined in the Synchronized Reserve Market to ensure that reserves are available in or deliverable to the eastern part of the system under constrained conditions. The Mid-Atlantic Sub-Zone is defined by the most limiting monitored transfer interfaces. The interface



modeled in SPREGO may be revised by PJM to match operation and meet the system reliability needs.

Certain topology configurations on the system may result in single contingencies that exceed what was previously defined as the Synchronized Reserve Requirement. During these periods, PJM may increase the Synchronized Reserve Requirement to accommodate the larger single contingency. Under most conditions, the increased Synchronized Reserve Requirement will be 75% of the larger single contingency during the off-peak period (0000 – 0459) and 100% of the larger single contingency during the on-peak period (0500 – 2359). This value may be further adjusted by PJM to meet the system reliability needs.

4.2.4 Synchronized Reserve Obligation Fulfillment

- Each Load Serving Entity (LSE) on the PJM system incurs a synchronized reserve obligation in kWh based on their real-time load ratio share and the Synchronized Reserve Zone total assigned MW. During hours when the Synchronized Reserve Market Clearing Price (SRMCP) is the same throughout the Synchronized Reserve Zone, an LSE's synchronized reserve obligation is equal to its load ratio share times the amount of synchronized reserve assigned for the Synchronized Reserve Zone. During hours when congestion causes Synchronized Reserve Market Clearing Prices (SRMCP) to separate each LSE's obligation is equal to its load ratio share within its sub-zone times the amount of synchronized reserve assigned in that sub-zone. Any PJM market participant may incur or fulfill a synchronized reserve obligation through the execution of a bilateral synchronized reserve transaction as described below.
- Participants may fulfill their synchronized reserve obligations by:
 - Owning Tier 1 resources from which the Synchronized Reserve Zone obtains synchronized reserve;
 - Self-scheduling owned Tier 2 resources;
 - Entering bilateral arrangements with other market participants; or
 - Purchasing synchronized reserves from the market.

Formatted: PJM Bullet 2, No bullets or numbering

4.2.5 Synchronized Reserve Offer Period

- Synchronized Reserve offer prices for Tier 2 resources and Synchronized Reserve Ramp Rates are locked as of 1800 hours on the day preceding the operating day. All resources listed as available for Tier 2 synchronized reserve with no offer price have their offer prices set to zero.



- The following information may be submitted and/or changed up until 60 minutes prior to the start of the operating hour, at which time the Synchronized Reserve Market closes:
 - Synchronized Reserve Availability for Tier 2 resources
 - Synchronized Reserve Offer Quantity (MW)
 - Synchronized Reserve Maximum (This parameter is called Spin Max on the eMKT Synchronized Reserve Hourly Updates screen)
- In general, generation owners may not self-schedule synchronized reserve resources after 60 minutes prior to the operating hour when the Synchronized Reserve Market closes. However, the following exceptions exist: if a generation owner has a resource that was either self-scheduled or pool-assigned to provide Tier 2 Synchronized Reserve and subsequent to either being self-scheduled or assigned that resource becomes unavailable to provide such amount of Synchronized Reserve, the generation owner has the option of self-scheduling another resource in order to make up the shortfall. Also, a resource that was unavailable for energy and therefore not evaluated as part of the Synchronized Reserve Market clearing becomes available during the operating hour, that resource may be self-scheduled to provide Synchronized Reserve at that time.

Formatted: PJM Bullet 2, No bullets or numbering

4.2.6 Bilateral Synchronized Reserve Transactions

- Bilateral synchronized reserve transactions may be reported to PJM. Such reported bilateral synchronized reserve transactions must be for the physical transfer of synchronized reserve and must be reported by the buyer and subsequently confirmed by the seller through the eMKT System no later than 16:00 the day after the transaction starts. Bilateral transactions that have been reported and confirmed may not be changed; they must be deleted and re-reported. Deletion of a reported bilateral transaction after its start time has passed will result in a change in the end time of the transaction to the current hour.
- Bilateral synchronized reserve transactions reported to PJM may be entered either in MW or as a percentage of the purchaser's obligation. Participants will also be required to indicate the reserve zone for which the transaction is applicable.
- Payments and related charges associated with the bilateral synchronized reserve transactions reported to PJM shall be arranged between the parties to the bilateral contract.
- A buyer under a bilateral synchronized reserve transaction reported to PJM agrees that it guarantees and indemnifies PJM, PJM Settlement, and the market participants for the costs of any purchases by the seller in the Synchronized Reserve Market, as determined by PJM, to supply the reported bilateral transaction and for which payment is not made to PJM Settlement by the seller.

Formatted: Tab stops: Not at 0"



- Upon any default in obligations to PJM or PJM Settlement by a Market Participant, PJM shall not accept any new bilateral reporting by the Market Participant and shall terminate all of the market participant's reporting of eMarkets schedules associated with its bilateral synchronized reserve transactions previously reported to PJM for all days where delivery had not yet occurred.
- PJM calculates and posts Synchronized Reserve Zone preliminary billing data on which market participants can use as a resource for pricing bilateral synchronized reserve transactions. The information can be found on the pjw website at <http://www.pjm.com/markets-and-operations/market-settlements/preliminary-billing-reports.aspx>.

4.2.7 Synchronized Reserve Market Clearing

- PJM clears the synchronized reserve market on an hourly basis. The following is the timeline by which this hourly clearing is accomplished:
- **90 minutes prior to the start of each hour**, PJM posts the estimates for the amount of Tier 1 synchronized reserve that will be available on each resource. PJM posts this information on the eMKT System such that each generation owner is able to view the Tier 1 assigned for each of the owner's resources.
- **60 minutes prior to the start of each hour**, each generation owner is required to identify those resources that are to be self-scheduled to provide synchronized reserve and for what quantity, if this information has changed from the previous hour.
- **30 minutes prior to the start of each hour**, PJM re-estimates the amount of Tier 1 synchronized reserve available on each resource simultaneously clears the synchronized reserve and regulation markets, and posts regulation market clearing prices, synchronized reserve market clearing prices and Tier 2 assignments, based on the remaining requirement not met by Tier 1 and self-scheduled Tier 2. If the available Tier 1 is sufficient to meet the synchronized reserve requirement, self-scheduled Tier 2 offers will not clear, no Tier 2 will be assigned, and the Tier 2 clearing price will be zero. If Tier 1 and self-scheduled Tier 2 resources are sufficient to meet the synchronized reserve requirement, the Tier 2 clearing price is zero and no Tier 2 pool-scheduled assignments are made (Tier 2 self-scheduled resources are committed and obligated to respond to a synchronized reserve event). If the available Tier 1 and self-scheduled Tier 2 are not sufficient to meet the requirement, the Tier 2 clearing price is set equal to the merit order price of the highest cost Tier 2 resource necessary to meet the remaining requirement. Should regulation and synchronized reserve capacity be insufficient to meet both requirements, regulation will receive the higher priority in the market clearing.

Resource merit order price (\$/MWh) = Resource synchronized reserve offer + estimated resource opportunity cost per MWh of capability + energy use per MWh of capability



The resource synchronized reserve offer is that which is submitted by the owner via the eMKT System by 1800 hours on the day preceding the operating day.

Estimated resource opportunity cost for condensing CTs is calculated as follows:

$$O.C. = [\text{positive (forecast LMP} - \text{energy offer price)}] \times \text{MW capability} / \text{synchronized reserve capability}$$

Estimated resource opportunity cost for non-condensing resources is calculated as follows:

$$O.C. = |LMP - ED| \times \text{GENOFF, where:}$$

LMP is the forecasted hourly LMP at the generator bus,

ED is the price associated with the setpoint the resource must maintain to provide its assigned amount of synchronized reserve, and

GENOFF is the MW amount of synchronized provided.

This formula is somewhat simplistic. The actual calculation is an integration that may be visualized as the area on a graph enclosed by the resource's price curve, the points on that curve corresponding to the resource's desired economic dispatch and the setpoint necessary to provide the assigned amount of synchronized reserve, and the LMP.

Energy use for each condensing resource is entered in MW by the owner via the eMKT System as part of the synchronized reserve offer. Estimated energy use is calculated as part of the merit order price as follows:

$$E.U. = \text{forecast LMP} \times \text{energy use MW} / \text{synchronized reserve capability}$$

For each of these calculations, forecast LMP is the result of the 1-hour look-ahead provided by the Unit Dispatch Tool.

Energy resources for which an energy offer is not submitted will be ineligible for opportunity cost credit.

The opportunity cost for a Demand Resource is zero.

- PJM may call on resources not otherwise scheduled to run in order to provide synchronized reserve, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. If a resource is called on by PJM for the purpose of providing synchronized reserve, the resource is guaranteed recovery of synchronized reserve lost opportunity costs as well as start-up, no-load and energy costs. Please refer to Manual 28: Operating Agreement Accounting for additional settlements details.
- Due to transmission considerations on the PJM system, it is sometimes necessary to carry a minimum amount of synchronized reserve in specific areas in PJM such that



loading 100% synchronized reserve will not result in an overload of any of the PJM transfer interfaces. The goal is to minimize the cost of synchronized reserve such that given current system conditions, the flow on binding transmission constraints is not increased after a synchronized reserve event is initiated and the associated response is achieved. Therefore, PJM clears the Tier 2 market based on this locational synchronized reserve requirement and calculates sub-zonal Tier 2 clearing prices. Whenever the locational synchronized reserve constraint is not binding, the clearing prices are equal. However, when more synchronized reserve is required in a given area than would have been assigned without this requirement, the clearing prices will separate. Resources will be identified and receive the applicable clearing price based on their location with respect to the binding constraint(s). That is, resources for which synchronized reserve response would help the constraint will receive the higher clearing price, whereas resources for which synchronized reserve response would aggravate the constraint will receive the lower clearing price. Analysis to determine the location of generation and load buses with respect to the binding constraint is performed with each quarterly network model update. The Mid-Atlantic sub-zone list resulting from this analysis can be found on the PJM Web site at <http://www.pjm.com/markets-and-operations/ancillary-services/synchronized-service.aspx>.

- The hourly Tier 2 clearing prices are posted on the eMKT user interface for public view.
- If no Synchronized Reserve Market Results are posted to the eMKT MUI for an hour, PJM will continue the current assignments, as needed, into the un-posted hour and the SRMCP from the previous hour will be used for settlement.

4.2.8 Hydro Units

- Hydro units condensing to provide synchronized reserve during times when they were not scheduled to generate incur no opportunity cost. There may or may not be an energy use component, as indicated by the owner as part of the synchronized reserve offer.
- If a hydro unit is held off line or reduced to provide synchronized reserve during a time when it was scheduled to generate, it will incur opportunity cost. Since hydro units operate on a schedule and do not have an energy bid, opportunity cost for these units is calculated as follows:

- The formula is the same as that shown under 'Synchronized Reserve Market Clearing', $O.C. = |LMP - ED| \times GENOFF$, except the ED value is the average value of the LMP at the hydro unit bus for the appropriate on-peak (0700 – 2259) or off-peak (0000 – 0659, 2300 - 2359) period, excluding those hours during which all available units at the hydro plant were operating. Day-ahead values are used for the purposes of assigning Tier 2 resources, and actual LMPs are used in the after-the-fact settlement. If the average LMP value is higher than the actual LMP at the generator bus, the opportunity cost is zero.

Formatted: PJM Bullet 2, No bullets or numbering



- During those hours when a hydro unit is in spill, the ED value is set to zero such that the opportunity cost is based on the full value of LMP. During the operating day, the operating company is responsible for communicating this condition on the Regulation Hourly Updates page in the eMKT System.
- When determined to be economically beneficial, PJM maintains the authority to adjust hydro unit schedules for those units scheduled by the owner if the owner has also submitted a synchronized reserve offer for those units and made the units available for spin.

4.2.9 Demand Resources

- Demand Resources providing Synchronized Reserve are required to provide metering information at no less than a one minute scan surrounding a synchronized reserve event.
- Metering information for demand resources is not required to be sent to PJM in real time. Daily uploads at the close of the next business day after the operating day, if an event has occurred are sufficient.
- Demand Resources are limited to providing 25% of the Synchronized Reserve requirement.
- Demand Resources that are considered to be “batch load” resources are limited to providing 20% of the Synchronized Reserve requirement. If PJM determines that satisfying 20 percent of the Synchronized Reserve requirement from Batch Load Demand Resources is causing or may cause a reliability degradation, PJM may reduce the percentage of the requirement that may be satisfied by Batch Load Demand Resources in any hour to as low as 10 percent.
- Demand Resources must complete initial and continuing training on Regulation and Synchronized Reserve Markets as documented in Manual 40: Certification and Training Requirements, Section 2.6: Training Requirements for Demand Response Resources Supplying Regulation and Synchronized Reserve.

4.2.10 Synchronized Reserve Market Operations



- The PJM Operator maintains the total Synchronized Reserve Zone Capability equal to the Synchronized Reserve Zone synchronized reserve requirement.
- The PJM Operator evaluates the set of resources providing synchronized reserve on an hourly basis, and assigns the most cost-effective set of Tier 2 resources necessary to fulfill the requirement.
- The hourly Tier 2 clearing price is fixed once calculated and posted. Any opportunity cost or energy use that exceeds the clearing price is credited after-the-fact on a resource-specific basis.
- The PJM Operator communicates Tier 2 condenser assignments to individual Local Control Centers via telephone.

4.2.11 Settlements

- Please refer to Manual 28: Operating Agreement Accounting, Section 6: Synchronized Reserve Accounting for settlement details.
- Synchronized Reserve settlement is a zero-sum calculation based on the synchronized reserve provided to the market by generation owners and purchased from the market by participants.
- Tier 1 credits will be awarded to each eligible resource for response up to 110% of the resource's capability based on the synchronized reserve ramp rate(s) submitted by the resource's owner day-ahead. Credits to individual resources may be awarded for response greater than 110% of stated capability if other Tier 1 resources under-respond. Credits for response in excess of 110% of capability will be awarded on a pro-rata basis such that the aggregate Tier 1 credits awarded do not exceed 110% of the total possible credits based on the aggregate capability of all eligible Tier 1 resources.
- Resources providing regulation at the initiation of a synchronized reserve event will be compensated for Tier 1 response. Tier 1 response is calculated according to the following formula:

$$\left\{ \left[\max\left(0, \int \left(\text{Output} - \min\left(\text{EcoMax}, \text{RegHighLimit}\right)\right)\right) \right] + \left[\max\left(0, \int \left\{ \min\left(\text{EcoMax}, \text{RegHighLimit}, \text{Output}\right) - \left[\text{Initial Output} - (2 \times \text{RegMW}) \right] \right\} \right) \right] \right\}, \text{ where :}$$



- Final Output is the resource's greatest telemetered output between 9 and 11 minutes after synchronized reserve event is initiated
- Initial Output is the resource's lowest telemetered output between 1 minute before and 1 minute after synchronized reserve event is initiated
- RegMW is the resource's assigned amount of regulation

As a result of this formula, resources that are assigned regulation when a synchronized reserve event is initiated will be compensated based on the amount of response provided beyond their regulation commitment, as well as for any response in excess of their regulation high limit or economic maximum (whichever is lower.) A resource's regulation maximum commitment will be defined as the resource's full regulating range (i.e. – twice the amount of assigned regulation.)

- Tier 2 synchronized reserve credits are awarded to generation owners that have either self-scheduled synchronized reserve or sold synchronized reserve into the market. Synchronized reserve credits for resources self-scheduled to provide synchronized reserve are equal to Tier 2 clearing price times the resource's self-scheduled synchronized reserve capability. Synchronized reserve credits for resources that are pool-scheduled to provide synchronized reserve are the higher of:
 - Tier 2 clearing price times the resource's assigned synchronized reserve capability, or
 - The resource's synchronized reserve offer times its assigned synchronized reserve capability plus opportunity cost and/or energy use incurred.
- Opportunity cost and energy use are calculated as shown above in Market Clearing using actual integrated LMP as opposed to that which was forecasted.
- Resources that are pool-assigned Tier 2 synchronized reserve (and actual MWh are less than day-ahead scheduled MWh) and Tier 1 resources that respond to a synchronized reserve event are therefore exempt from deviations for the purpose of accumulating operating reserves charges for the hours during which the Tier 2 assignment or Tier 1 response is effective.

4.2.12 Verification

- The magnitude of each resource's response to a synchronized reserve event (both Tier 1 and Tier 2) is the difference between the resource's output at the start of the event and its output ten minutes after the start of the event. In order to allow for small fluctuations and possible telemetry delays, resource output at the start of the event is defined as the lowest telemetered output between one (1) minute prior to and one (1) minute following the start of the event. Similarly, a resource's output ten minutes after the event is defined as the greatest output achieved between nine (9) and eleven (11) minutes after the start



of the event. All resources (both Tier 1 and Tier 2) must maintain an output level greater than or equal to that which was achieved as of ten minutes after the event for the duration of the event or thirty (30) minutes from the start of the event, whichever is shorter. The response actually credited to a given resources will be reduced by the amount the MW output of that resource falls below the level achieved after ten (10) minutes by either the end of the event or after 30 minutes from the start of the event, whichever is shorter.

- For demand resources that are considered “batch load” resources, a second method of verification will be used for instances where a synchronized reserve event is initiated and the resource is operating at the minimum consumption level of its duty cycle. In this case, the magnitude of the response will be measured as the difference between (a) the resource’s consumption at the end of the event and (b) the maximum consumption within a ten (10) minute period following the event provided that all subsequent minutes following that minute are no less than 50% of the consumption in that minute.

4.2.13 Non-Performance

- There is no consequence for a Tier 1 resource that does not respond with the amount of synchronized reserve that was expected of it in response to a synchronized reserve event. Tier 1 resources are simply credited for the amount of response they provide.
- Since Tier 2 resources are credited with a capacity payment any time they are expected to be ready to respond to a synchronized reserve event, failure to provide that response results in an obligation to “repay” that credit following instances of non-performance. The following consequences exist for a Tier 2 resource that does not respond with its assigned amount of synchronized reserve:
 - The resource is credited for Tier 2 synchronized reserve capacity in the amount that actually responded for the contiguous hours the resource was assigned Tier 2 synchronized reserve during which the event occurred, and;
 - The owner of the resource incurs a synchronized reserve obligation in the amount of the shortfall for the three (3), consecutive, same-peak days occurring at least three (3) business days following the event. Off-peak days are defined as weekends and PJM holidays, and on-peak days are all others. Owners of assigned Tier 2 resources will be permitted to demonstrate aggregate response, such that the total response from all assigned resources must be greater than or equal to the total assigned amount of synchronized reserve. This aggregate response will be used when determining the owner’s additional obligation.
- In cases where a synchronized reserve event lasts less than 10 minutes, Tier 2 resources are credited with the amount of synchronized reserve capacity they are assigned. Tier 1 resources are credited with the amount of response provided over the length of the event, as determined via measurement parallel to that which is described above in the Verification section. That is, the output of each resource at the start of the



event is defined as the lowest telemetered output between one (1) minute prior to the start of the event and one (1) minute after the start of the event, and the output at the end of the event is defined as the greatest telemetered output between one (1) minute prior to the end of the event and one (1) minute following the end of the event.



Section 5: Market Clearing Processes and Tools

Welcome to the Market Clearing Processes and Tools section of the **PJM Manual for Energy & Ancillary Services Market Operations**. In this section you will find the following information:

- A description of the PJM scheduling philosophy (see “*PJM Philosophy*”).
- A description of the tools that are used during the scheduling process (see “*Scheduling Tools*”).

5.1 PJM Philosophy

The PJM scheduling philosophy in the Day-ahead Energy Market is to schedule generation to meet the aggregate Demand bids that results in the least-priced generation mix, while maintaining the reliability of the PJM RTO. PJM will also schedule additional resources as needed to satisfy the PJM Load Forecast and the additional Day-ahead Scheduling Reserve (Operating Reserve) Objective based on minimizing the cost to procure such reserves. PJM will also schedule resources based on economics to control potential transmission limitations that are binding in the Transmission Reliability analysis that is performed in parallel with and subsequent to the Day-ahead Market analysis. The scheduling process evaluates the price of each available resource compared with every other available generating resource. The philosophy for scheduling the PJM RTO requires:

- Scheduling sufficient generation in the Day-ahead Energy Market to cover aggregate Demand bids and Day-ahead Scheduling Reserve (Operating Reserve) requirements calculated as a function of such demand bids
- Scheduling sufficient generation in the reliability-based analysis subsequent to the Day-ahead Energy Market to cover the PJM Load Forecast and additional Day-ahead Scheduling Reserve (Operating Reserve) requirements
- Scheduling sufficient generation to control potential transmission limitations that are binding in the Transmission Reliability analysis
- Scheduling sufficient generation to satisfy the PJM Regulation Requirement, PJM Synchronized Reserve Requirement, and other ancillary service requirements of the PJM RTO.
- Ensuring PJM Members participate in the analysis and elimination of conditions that threaten the reliable operation of the PJM RTO

Scheduling of resources by PJM is performed economically on the basis of the prices and operating characteristics offered by the Market Sellers, using security, constrained dispatch and continuing



until sufficient generation is dispatched in each hour to serve all energy purchase requirements, as well as the PJM RTO requirements.

5.2 Scheduling Tools

Analytical scheduling tools exist to assist PJM with the scheduling process. These tools permit PJM scheduling staff to analyze numerous scheduling scenarios. PJM personnel use several tools to assist in scheduling the resources for short-term and hourly activities. The scheduling tools include:

- PJM Enhanced Energy Scheduler (EES)
- PJM eSchedules
- Load Forecasting Algorithms
- eMKT and Market Database System
- Unit Dispatch System (UDS)
- Hydro Calculator
- Energy Market Technical Software (RSC, SPD and SFT)
- PJM Synchronized Reserve and Regulation Scheduling Software (SPREGO)
- Transmission Outage Data System

Together these tools recognize the following conditions:

- Reactive limits
- Resource constraints
- Unscheduled power flows
- Inter-area transfer limits
- Resource distribution factors
- Self-Scheduled Resources
- Limited fuel resources



- Bilateral Transactions
- Hydrological constraints
- Generation requirements
- Reserve requirements

5.2.1 Enhanced Energy Scheduler (EES)

The EES program records and manages the interchange of bulk power between the PJM RTO and other utilities, marketers, and brokers. PJM personnel use EES to process daily non-firm (both those electing to curtail due to congestion and those electing to pay congestion charges) and firm Bilateral Transaction schedules that are submitted by PJM Members. In general, EES is used to perform the following activities:

- Processes PJM Members' Bilateral Transactions
- Validates transaction by verifying transaction rules

Bilateral transactions that are reported to PJM must be for the physical transfer of electric energy. Payments and related charges associated with such bilateral electric energy transactions reported to PJM shall be arranged between the parties to the bilateral transaction. A buyer under a bilateral transaction reported to PJM agrees that it guarantees and indemnifies PJM, PJM Settlement, and the market participants for the costs of any Spot Market Backup, as determined by PJM, to supply the reported bilateral transaction and for which payment is not made to PJM Settlement by the seller. Upon any default in obligations to PJM or PJM Settlement by a Market Participant, PJM shall not accept any new bilateral transaction reporting by the Market Participant and shall terminate all of the market participant's reporting of associated with its bilateral transactions previously reported to PJM for all days where delivery had not yet occurred.

5.2.2 PJM eSchedules

PJM eSchedules is an Internet application that is used, among other functions, to report internal Bilateral Transactions.

5.2.3 Load Forecasting

PJM scheduling staff requires load forecasts for up to ten days in the future. For each day, a 24-hour load shape is needed.

- The first step in developing a load forecast is to obtain the weather information for the time period. Weather information is provided to PJM at regular intervals by a contracted-for weather service. Additional weather data sources include the National Weather Service, radio news, LSE weather information, and existing local PJM RTO conditions.
- The forecast period is reviewed to determine any conditions that could affect the PJM RTO's load, including:
 - Day of week
 - Holidays
 - Special events
 - Daylight savings time changes
 - Internal participant load forecasts
 - Peak loads and load shapes are determined using a similar day's forecast. PJM retrieves the load data from a historical file and adjusts the forecasts, as needed, to reflect growth or other discrepancies.

Formatted: PJM Bullet 2, No bullets or numbering

Exhibit 2 presents the typical approach PJM uses to forecast load.

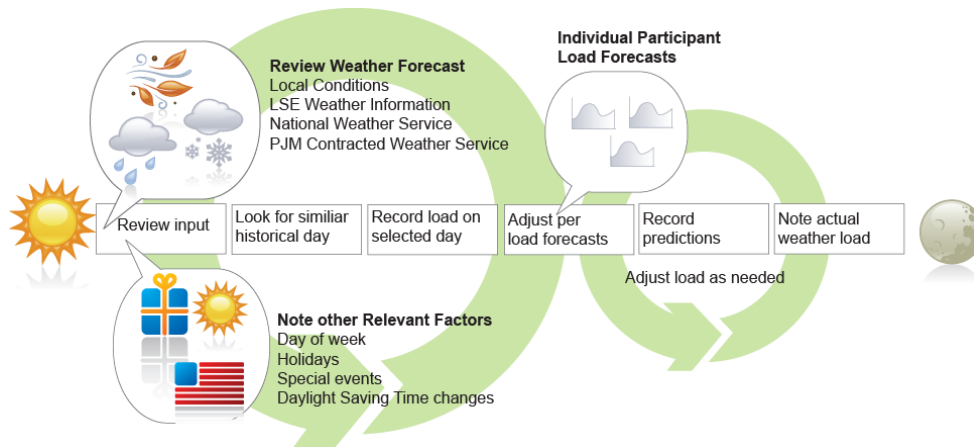


Exhibit 2: Load Forecasting Process



The load forecasts for each 24-hour period are input in the Marginal Scheduler program. PJM scheduling staff also posts these forecasts on the OASIS.

5.2.4 Markets Database System

The Markets Database System is a two-part system:

- The Markets Database stores the basic resource data supplied by the PJM Members, including operating limits and resource availability.
- The eMKT Web site that provides the Internet-based user interface that allows Market participants to submit generation offer data, Demand bids, Increment Offers, Decrement bids and Regulation Offers, Synchronized Reserve Offers, into the Markets Database.

The Markets Database is a very large database that contains information on each generating resource that operates as part of the PJM Energy Market, Demand Information, Increment Offers, Decrement Bids, Regulation Offers, Synchronized Reserve Offers, Day-ahead Energy Market results, Day-ahead Scheduling Reserve Market Clearing Prices, Regulation Market Clearing Prices and Synchronized Reserve Market Clearing Prices. A description of the Markets Database can be found in the [Markets Database Dictionary](http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf) (<http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf>).

Market participants may access the Markets Database by using the PJM eMKT Web site via the Internet using manual entry or bulk upload/download via XML format.

Please refer to Exhibit 3: Energy Market Daily Timeline.



Exhibit 3: Synchronized Reserve and Regulation Market Daily Timeline

Please refer to Exhibit 4: Synchronized Reserve and Regulation Market Hourly Timeline.

- PJM clears the synchronized reserve and regulation markets on an hourly basis. The following is the timeline by which this hourly clearing is accomplished:
- **90 minutes prior to the start of each hour**, PJM estimates the amount of Tier 1 synchronized reserve that will be available on each resource. PJM posts this information on eMKT such that each generation owner is able to view the Tier 1 assigned for each of the owner's resources.
- **60 minutes prior to the start of each hour**, each generation owner is required to identify those resources that are to be self-scheduled to provide synchronized reserve and for what quantity, if this information has changed from the previous hour.
- **30 minutes prior to the start of each hour**, PJM re-estimates the amount of Tier 1 synchronized reserve available on each resource simultaneously clears the synchronized reserve and regulation markets, and posts regulation market clearing prices, synchronized reserve market clearing prices and Tier 2 assignments, based on the remaining requirement not met by Tier 1 and self-scheduled Tier 2. If the available Tier 1 is sufficient to meet the synchronized reserve requirement, self-scheduled Tier 2 offers will not clear, no Tier 2 will be assigned, and the Tier 2 clearing price will be zero. If Tier 1 and self-scheduled Tier 2 resources are sufficient to meet the synchronized reserve requirement, the Tier 2 clearing price is zero and no Tier 2 pool-scheduled assignments are made (Tier 2 self-scheduled resources are committed and obligated to respond to a synchronized reserve event). If the available Tier 1 and self-scheduled Tier 2 are not sufficient to meet the requirement, the Tier 2 clearing price is set equal to the merit order price of the highest cost Tier 2 resource necessary to meet the remaining requirement. Should regulation and synchronized reserve capacity be insufficient to meet both requirements, regulation will receive the higher priority in the market clearing.

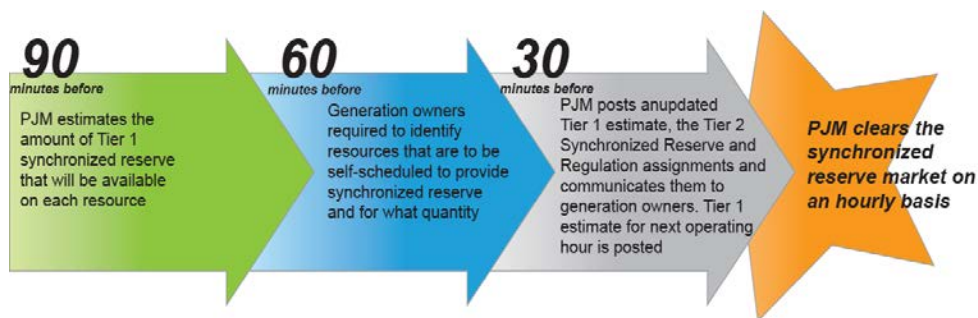


Exhibit 4: Synchronized Reserve and Regulation Market Hourly Timeline



The data that needs to be submitted by PJM Members to participate in the Day-ahead Energy, Synchronized Reserve, and Regulation Markets is described in detail in the [Markets Database Dictionary \(http://www.pjm.com/markets-and-operations/etools/~media/etools/emkt/market-database-data-dictionary.ashx\)](http://www.pjm.com/markets-and-operations/etools/~media/etools/emkt/market-database-data-dictionary.ashx)

5.2.5 Hydro Calculator

For PJM RTO-Scheduled Resources, PJM is responsible for developing the schedules for the run-of-river and pumped storage plants located within the PJM RTO and turned over to PJM for coordination. To assure hydraulic coordination of the hydro plants, PJM uses a computer program called the Hydro Calculator. The Hydro Calculator computes hourly reservoir elevations and plant generation from input river flows and plant discharges. PJM scheduling staff uses the Hydro Calculator to concentrate on economic placement of available hydro energy.



5.2.6 PJM Energy Market Technical Software

The PJM Energy Market Technical Software is a set of computer programs, which performs a security-constrained resource commitment and economic dispatch for the Day-ahead Market. The individual programs are:

Resource Scheduling & Commitment (RSC) – Performs security-constrained resource commitment based on generation offers, demand bids, Day-ahead Scheduling Reserve Offers, Increment Offers, Decrement bids and transaction schedules submitted by participants and based on PJM RTO reliability requirements. RSC will enforce physical resource specific constraints that are specified in the generation offer data and generic transmission constraints that are entered by the Market Operator. RSC provides an optimized economic resource commitment schedule for the next seven days and it utilizes a Mixed Integer linear programming solver to create an initial resource dispatch for the next operating day.

Scheduling, Pricing, & Dispatch (SPD) – Performs security-constrained *economic dispatch* using the commitment profile produced by RSC. SPD calculates hourly resource generation MW levels, LMPs and Day-ahead Scheduling Reserve Clearing Prices for all load and generation buses for each hour of the next operating day. SPD utilizes a linear programming solver to develop the economic dispatch solution while respecting generic transmission constraints that affect dispatch, such as reactive interface limits, and thermal limits.

Simultaneous Feasibility Test (SFT) – SFT performs AC contingency analysis using contingency list from PJM EMS and creates generic constraints equations based on any violations that are detected. These generic constraints equations are then passed them back to SPD for resolution. SFT ensures that the Day-ahead Market results are physically feasible considering PJM RTO security constraints and reliability requirements.

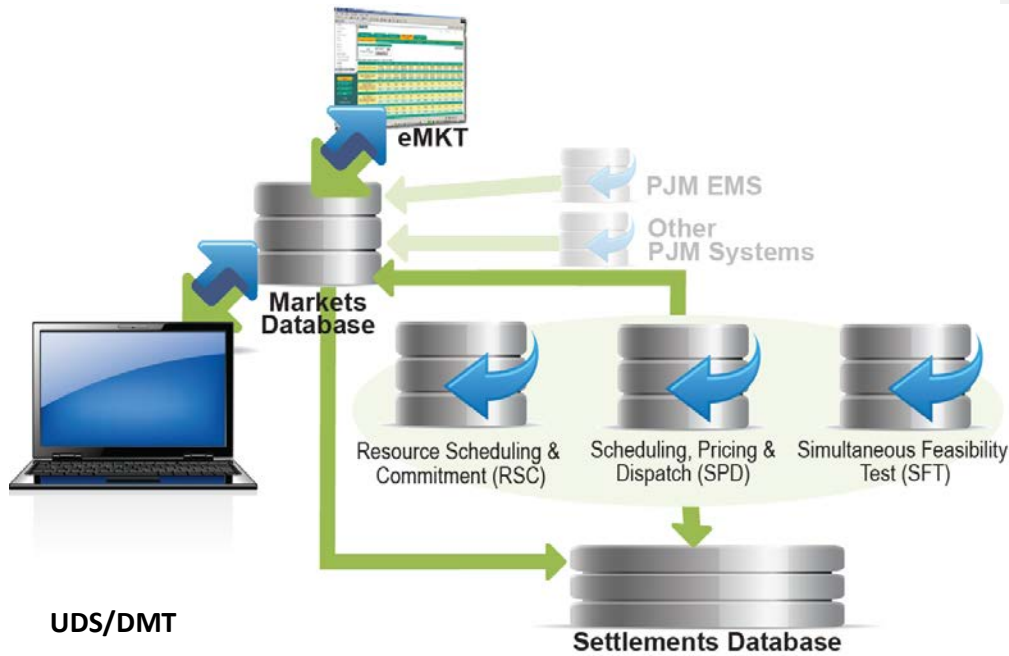


Exhibit 5: Settlement Subsystems

The Energy Market technical software develops the Day-ahead Market results based on minimizing production cost of energy and reserve to meet the Demand bids and Decrement bids that are submitted into the Day-ahead Market while respecting the PJM RTO security constraints and reliability requirements that are necessary for the reliable operation of the PJM RTO.

Subsequent to the close of the generation Re-bidding Period at 6:00 PM, the RSC is the primary tool used to determine any change in steam resource commitment status based on minimizing the additional startup costs and costs to operate steam resources at economic minimum in order to provide sufficient operating reserves to satisfy the PJM Load Forecast (if greater than cleared total demand in the Day-ahead Market) and adjusted Day-ahead Scheduling Reserve (Operating Reserves) requirements. The purpose of this second phase of resource commitment is to ensure that PJM has scheduled enough generation in advance to meet the PJM Load Forecast for the next operating day and for the subsequent 6 days. CTs resources are included in the scheduling process and are scheduled in the Day-ahead Market. However, the decisions concerning actual operation of

pool-scheduled CT resources during the operating day are not made until the current operating hour in real-time dispatch.

Download Data from Markets Database

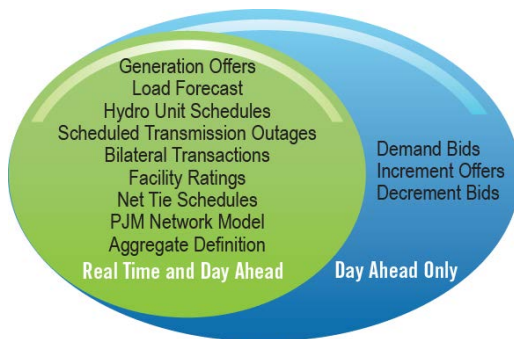


Exhibit 6: Download Data from Markets Database

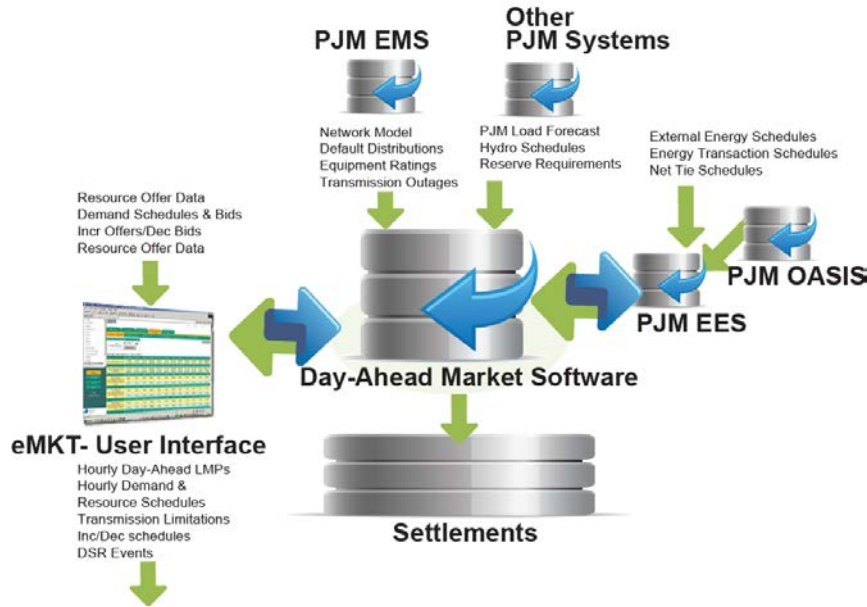


Exhibit 7: Energy Market Data Flow

5.2.7 Synchronized Reserve and Regulation Scheduling Software (SPREGO)

The SPREGO is the synchronized reserve and regulation market software. It uses the regulation offers, synchronized reserve offers, and commitment data to determine the regulation market clearing price (RMCP) and synchronized reserve market clearing price (SRMCP). It also determines a preliminary forecast of which resources will provide regulation and synchronized reserve. SPREGO performs regulation and synchronized reserve market dispatch to minimize the total cost of energy, regulation and synchronized reserve dispatch.

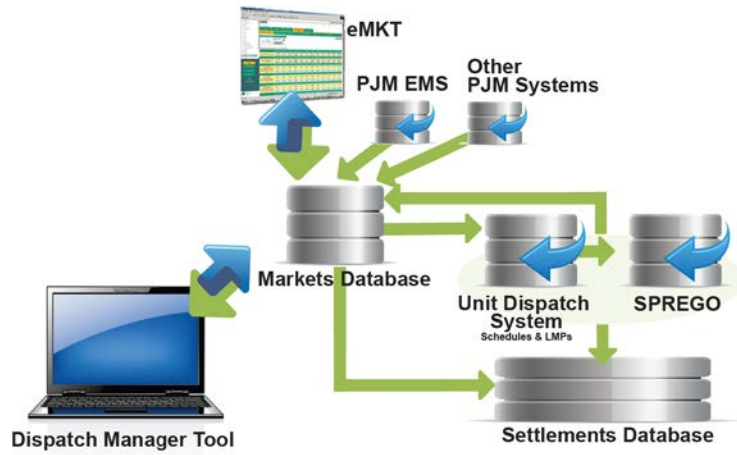


Exhibit 8: *Synchronized Reserve and Regulation Subsystems*



Section 6: Reserve Requirements in PJM Energy Markets

Welcome to the *Reserve Requirements in PJM Energy Markets* section of the PJM Manual for **Energy & Ancillary Services Market Operations**. In this section you will find the following information:

- A description of the requirement/supply relationship (see “*Forecasting PJM Generation Requirement*”).
- How PJM regulation requirements are determined (see “*PJM Regulation Requirements*”).
- How PJM synchronized reserve requirements are determined (see “*PJM Synchronized Reserve Requirements*”).
- How the marketing information is processed (see “*Processing Market Information*”).

Scheduling bridges the gap between advance outage and market information (pre-scheduling) and real-time operations (dispatching) of monitored facilities. Details on the dispatching procedures for all facilities can be found in **PJM Manual 12 Dispatch Operations**. The goal of the PJM is to develop schedules that preserve the security of the PJM RTO on an unbiased basis for all PJM Members. The scheduling process for each day consists of the Day-ahead Energy Market and of the development Current Operating Plan (COP) based on reliability analysis that is performed in parallel with and subsequent to the Day-ahead Energy Market clearing.

6.1 Forecasting PJM Generation Requirement

The first step in the scheduling process is to examine the relationship between Day-ahead Demand Bids and Decrement Bids with and Generation Offers and Increment Offer and to clear the Day-ahead Market based on these bids and offers. In the reliability analysis that follows the Day-ahead Market, the relationship between PJM Load Forecast requirement and generation supply for the Real-time Energy Market is considered. Exhibit 9 illustrates the Real-time Market relationships in the form of a bar chart.

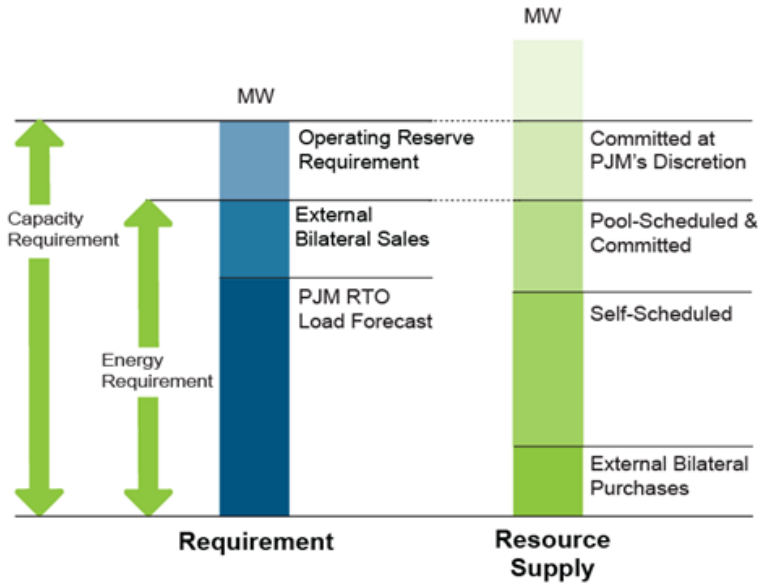


Exhibit 9: Requirement Versus Resource Supply

Exhibit 9 presents the following information:

- The PJM requirement is represented by the bar on the left. The height of this bar is the total PJM capacity requirement in MW. The capacity requirement consists of two components:
 - Energy requirement, consisting of the PJM load forecast plus External Transaction sales to External Control Areas
 - Day-ahead Scheduling Reserve (Operating Reserve) requirement
- The PJM resource supply is represented by the bar on the right which consists of four supply components:
 - External Transaction purchases from External Control Areas
 - Resources that are self-scheduled by the PJM Members
 - Resources and capacity that has been bid into the Day-ahead Market and the Real-time Market and is scheduled by PJM to meet the energy and reserve requirement

Formatted: PJM Bullet 2, No bullets or numbering

Formatted: PJM Bullet 2, No bullets or numbering



- o Additional capacity to satisfy the Day-ahead Scheduling Reserve (Operating Reserve) requirement is committed at the discretion of the PJM

The identity of the resources that are self-scheduled or PJM RTO-scheduled is given by the market information contained in the Markets Database as shown in the [Markets Database Dictionary](http://www.pjm.com/markets-and-operations/etools/-/media/etools/emkt/market-database-data-dictionary.ashx) (<http://www.pjm.com/markets-and-operations/etools/-/media/etools/emkt/market-database-data-dictionary.ashx>).

The PJM RTO's load forecast is described in Section 2 of this PJM Manual. The amount of External Transactions as scheduled by the PJM Members is also considered when establishing the amount of generation that must be scheduled.

So far, we have only discussed the basic requirement/supply relationships. The details of how we actually match the resources with the corresponding loads for both the Day-ahead Energy Market and the Real-time Energy Market are discussed in later subsections.

6.1.1 PJM Regulation Requirement

- The total PJM Regulation Requirement for the PJM RTO is determined in whole MW for the on-peak (0500 – 2359 and off-peak (0000 – 0459) periods each day.
- The PJM RTO on-peak Regulation Requirement is equal to 1% of the forecast peak load for the PJM RTO for the day. The PJM RTO off-peak Regulation Requirement is equal to 1% of the forecast valley load for the PJM RTO for the day.

PJM Actions:

The PJM actions that are performed to clear the Regulation Market by establishing the initial list of resources to provide regulation for the next On/Off-Peak Period and by calculating the Regulation Marginal Clearing Prices (RMCP) are as follows:

- PJM clears the Regulation Market simultaneously with the Synchronized Reserve Market, and posts the results no later than 30 minutes prior to the start of the operating hour.
- The PJM Operator maintains total PJM regulating capability within a 30MW bandwidth around the Regulation Requirement.
- The PJM Operator periodically evaluates the set of resources providing regulation, and makes any adjustments to regulation assignments deemed necessary and appropriate to minimize the overall cost of regulation.
- In the event of a regulation excess, the PJM dispatcher deselects resources beginning with the highest cost resource currently providing regulation and moving downward.



- In the event of a regulation deficiency, the PJM dispatcher selects resources to provide regulation beginning with the lowest cost resource currently not providing regulation and moving upward.
- The RMCP does not change based upon regulating resource adjustments made in real time. Any opportunity costs that exceed the RMCP are credited after the fact on a resource -specific basis.
- The PJM Energy Management System (EMS) sends one Area Regulation signal to each Local Control Center (LCC), as well as signals to individual resources or plants as requested by the owner.
- The PJM Operator communicates any change in resource regulating assignments to individual Local Control Centers. Company total in-service regulating capabilities are then telemetered back to the PJM EMS via the PJM data link.
- Resource regulation assignment changes during transitions between on-peak and off-peak periods begin 30 minutes prior to the new period, and are completed no later than 30 minutes after the period begins.

Hourly participant Regulation obligations are determined after-the-fact, based on the LSE's actual load ratios. Participants can estimate their share of the PJM Regulation Requirement in advance by comparing their hourly load forecast to the PJM hourly load forecasts provided by the PJM.

PJM Member Actions:

- PJM Members submit Individual Synchronized Reserve and Regulation offer data for each Resource that is available to provide synchronized reserve and/or regulation (for generation or demand resources meeting the Regulation quality standard and Synchronized Reserve quality standard), differentiated as self-scheduled, External Transaction sale/purchase (identifying seller and buyer) and available for PJM RTO-scheduling. This information is maintained within the PJM eMKT Web site and is passed to the PJM Synchronized Reserve and Regulation Software (SPREGO). Exhibit 10 summarizes this information.

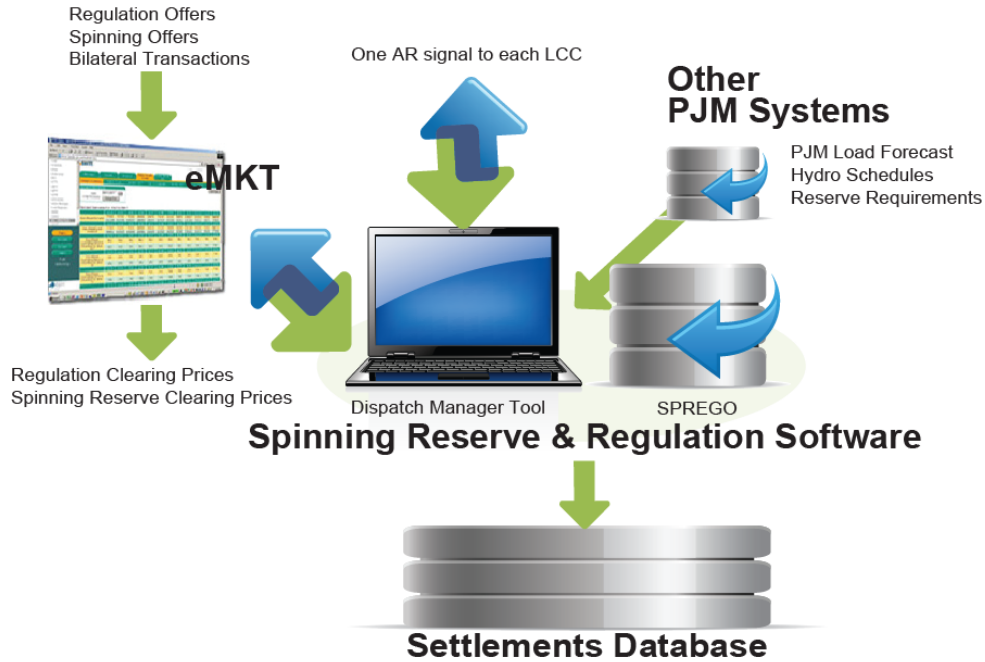


Exhibit 10: Synchronized & Regulation Data Flow

PJM Members update regulating resource operating limits and availability in the PJM eMKT Web site.

6.1.2 Regulation Service

PJM operates a bidding market for Regulation services in the PJM RTO. PJM Members that have generation or demand resources meeting the Regulation quality standard may submit Regulation offer data for each individual Resource that is available to provide regulation. The offer information is maintained within the PJM eMKT Web site and is passed to the Synchronized Reserve and Regulation software (SPREGO). Generation owners wishing to sell regulation service must supply a regulation offer price by 6:00 p.m. the day prior to operation and is applicable for the entire 24-hour period for which it is submitted. The remainder of the necessary data may be submitted or changed up until sixty (60) minutes prior to the operating hour, at which time the Regulation market closes.



Exhibit 11 defines the Regulation parameters of a qualified generating resource.

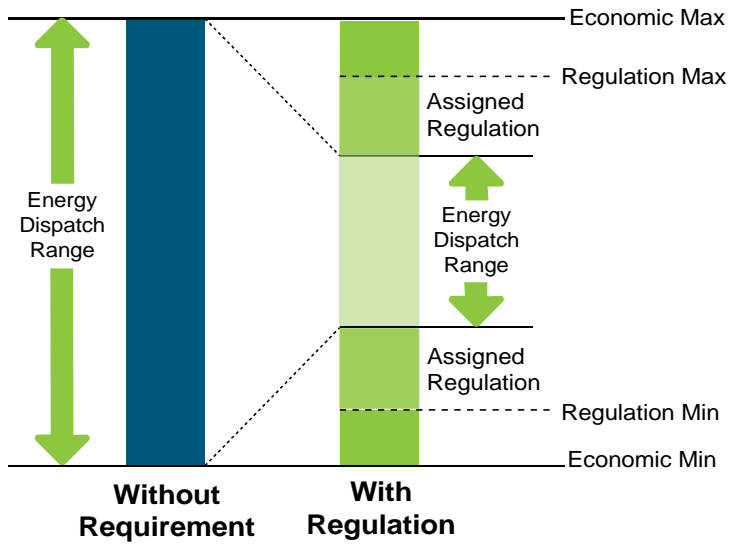




Exhibit 11: Generator Regulation Service

The PJM RTO's total available Regulation service is calculated and compared with its requirements. Any significant shortage is reported to PJM dispatcher for possible action. See the **PJM Manual for [Balancing Operations \(M-12\)](#)** for a description of the Regulation allocation process during the course of system operation.

6.2 PJM Synchronized Reserve Requirements

The total PJM Synchronized Reserve Requirement for each Synchronized Reserve Zone is determined in whole MW for each hour of the operating day.

The RFC Synchronized Reserve Zone Requirement is defined as that amount of 10-minute reserve that must be synchronized to the grid. The requirement will be defined as the greater of the ReliabilityFirst Corporation (RFC) imposed minimum requirement or the largest contingency on the system.

The Southern Synchronized Reserve Zone Requirement is defined as the Dominion load ratio share of the largest system contingency within VACAR, minus the available 15 minute quick start capability within the Southern Synchronized Reserve Zone.

PJM Actions:

The PJM actions that are performed to clear the Synchronized Reserve Market by establishing the initial list of resources to provide Synchronized Reserve for the next operating day and by calculating the Synchronized Reserve Marginal Clearing Prices (SRMCP) for each hour as follows:

- PJM clears the Synchronized Reserve Market simultaneously with the Regulation Market, and posts the results no later than 30 minutes prior to the start of the operating hour
- The PJM Operator maintains total Synchronized Reserve Zone Capability equal to the Synchronized Reserve Zone synchronized reserve requirement.
- The PJM Operator evaluates the set of resources providing synchronized reserve on an hourly basis, and assigns the most cost-effective set of Tier 2 resources necessary to fulfill the requirement.
- The hourly Tier 2 clearing price is fixed once calculated and posted. Any opportunity cost or energy use that exceeds the clearing price is credited after-the-fact on a resource-specific basis.
- The PJM Operator communicates Tier 2 condenser assignments to individual Local Control Centers via telephone.



Hourly participant Synchronized Reserve obligations are determined after-the-fact, based on the LSE's actual load ratios. Participants can estimate their share of the PJM Synchronized Reserve Requirement in advance by comparing their hourly load forecast to the PJM hourly load forecasts provided by the PJM.

PJM Member Actions:

- PJM Members submit Individual Synchronized Reserve and Regulation offer data for each Resource that is available to provide Synchronized Reserve and/or regulation (for generation or demand resources meeting the Regulation quality standard and Synchronized Reserve quality standard), differentiated as self-scheduled, External Transaction sale/purchase (identifying seller and buyer) and available for PJM RTO-scheduling. This information is maintained within the PJM eMKT website and is passed to the PJM Synchronized Reserve & Regulation Software (SPREGO).

PJM Members update regulating resource operating limits and availability in the PJM eMKT Web site.

6.2.1 Synchronized Reserve Service

PJM operates a bidding market for Synchronized Reserve services in the PJM RTO. PJM Members that have resources meeting the Synchronized Reserve quality standard may submit Synchronized Reserve offer data for each individual resource that is available to provide synchronized reserve. The offer information is maintained within the PJM eMKT Web site and is passed to the Synchronized Reserve and Regulation Market software (SPREGO). Resource owners wishing to sell synchronized reserve or regulation service must supply an offer price by 6:00 p.m. the day prior to operation and is applicable for the entire 24-hour period for which it is submitted. The remainder of the necessary data may be submitted or changed up until sixty (60) minutes prior to the operating hour, at which time the Regulation and Synchronized Reserve markets close.

6.3 Processing Market Information

Our attention now focuses on the elements that make up the requirement and supply picture in both the Day-ahead Energy Market and in the Real-time Energy Market. In the Day-ahead Energy Market, participants submit Demand bids, Demand Reduction Bids, Decrement Bids, Increment Offers and Generation Offers into the Day-ahead Energy Market and PJM clears the Market based on these bids and offers using least-cost security-constrained resource commitment and dispatch. .

6.3.1 PJM Member Load Forecasts



Each PJM Electric Distribution Company (EDC) within the PJM RTO provides PJM with a forecast of its requirements by noon on the day before the Operating Day. Regardless of how the PJM EDC's load is supplied, the PJM EDC submits the following Operating Day forecast information to the PJM:

- Midnight valley MW
- Morning peak MW
- Afternoon peak MW
- Evening peak MW

The hours for which the forecasts apply are specified and changed periodically by PJM and communicated to the PJM Members either electronically or by facsimile.

PJM compares the forecasts submitted by the PJM Members against the PJM RTO load forecast which is developed by PJM. The PJM Members' forecasts cover only four specified hours, while the PJM RTO forecast is for each hour of the Operating Day. Any significant discrepancies between the PJM Members' forecasts and the corresponding PJM RTO forecasts are reported to PJM dispatcher. In general, the PJM RTO forecast takes precedence over the aggregate of the individual PJM Members' forecasts.

6.3.2 Reserve Service

The Day-ahead Scheduling Reserve (Operating Reserve) objective is a Control Zone requirement (not allocated to PJM Members individually). PJM schedules sufficient generating resources to meet the PJM Day-ahead Scheduling Reserve (Operating Reserve) objective as part of the Day-ahead Scheduling Reserve Market Clearing process. See the **PJM Manual for [Pre-Scheduling Operations \(M-10\)](#)** for the detailed methodology for determining Reserve Requirements.

6.3.3 Self-Scheduled Resources

PJM Members can choose to self-schedule their generation in the Day-ahead Market or to Offer into the Day-ahead Market and allow PJM to schedule their generation in the Day-ahead Market. Subsequent to the Day-ahead Market, any generator that was not selected in the Day-ahead Market may choose to self-schedule. Another option is to purchase generation from the market. The PJM Members' scheduling choice is dependent on their scheduling philosophy.

6.3.4 Deviations from Day-ahead Market for Pool Scheduled Resources



If a generation resource has been scheduled in the Day-ahead Market and wishes to deviate from that schedule (i.e. not run), the generation owner should contact the PJM Scheduling Coordinator to determine if this course of action is possible. The PJM Scheduling Coordinator will then:

- If the PJM Scheduling Coordinator determines that the generation resource is not needed for reliability purposes for the operating day, the generation owner can decide not to run the resource and no forced outage will be incurred. The generation owner will be responsible for all imbalance and operating reserve charges.
- If the PJM Scheduling Coordinator determines that the resource is needed for reliability purposes, he/she will inform the generation owner. The generation owner may still elect to not run the resource, but a forced outage for the duration of the scheduled operation of the resource will be generated. The generation owner will be responsible for all imbalance and operating reserve charges.

The guideline for notifying PJM of deviations for pool scheduled resources will be the sum of the resource's notification time plus the time to start. If this sum totals to zero, then the minimum notification time will be 45 minutes prior to the scheduled operation of the resource. This allows PJM adequate time for determining if the resource is needed for reliability.

6.3.5 Credits for Cancellation of Pool Scheduled Resources

At the end of each month, PJM calculates the credits due to each PJM Member for pool-scheduled resources that were selected to run as part of the reliability study, and that PJM canceled before coming on-line. The cancellation credit equals the actual costs incurred, capped at the appropriate start-up cost as specified in the generating resource's offer data. Requests for such credits must be submitted, in writing, to the PJM Manager of Market Settlement Operations Department, within forty-five days of invoice being received by participant for the month in question.

6.3.6 Resource Specific Data Requirements

Internal PJM Members Offer Data for resource specific offers is submitted directly into the Markets Database via the eMKT Web site. Exhibit 15 summarizes the data requirements for capacity and energy



resources.

Capacity and Energy Only Data Requirements		
Resource Type	Input Requirements	Data Requirements
Capacity	Next day and following six days	Availability status startup and no-load, if cost-based (If price-based, startup and no-load fees are updated biannually as detailed in Section 1 of the PJM Manual for Pre-Scheduling Operations (M-10))
	Next day and optionally for the following six days	Minimum energy Maximum energy Regulation availability Incremental price points Resource characteristics
	Next day	Must run output Whether or not to request bid acceptance notification by 4:00 p.m.
Energy only	Next day	Availability status Must run output

Exhibit 12: Capacity and Energy Resource Data Requirements

If offer data for a capacity resource is not submitted by 12:00 noon of the day before the operating day, PJM uses the offer data and resource availability previously entered into the Markets Database and considers the data a binding offer. For a more detailed description of the data, please see the [PJM Markets Database Dictionary \(http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf\)](http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf).

6.3.7 External Market Sellers

An External Resource is a generation resource that is located outside the metered boundaries of PJM. If an external resource is qualified as a capacity resource in PJM, then in accordance with the PJM Tariff, all external resources being offered in as capacity resources must bid into the PJM Day-ahead Market as generation resources.

For an external resource to be offered as a unit resource, a valid generator offer, which consists of a price-based schedule, is submitted in the eMKT system and a valid energy schedule is submitted in the EES system.

External Market sellers report the following data for resource-specific offers, reported on the business day before the next operating day, up to seven days in advance:



- Specific generation resource (the CCPPTTUUSS reference number and resource name from The Markets Database). This number is supplied by PJM to the PJM Member upon creation of the resource in the Markets Database. If the resource is submitted at least 30 days before the bid date, see the [PJM Manual for Pre-Scheduling Operations \(M-10\)](#).
- Minimum and maximum energy for each hour
- Minimum and maximum generation for each hour
- Minimum and maximum run times
- Resource availability for each hour
- Availability of regulation upper and lower energy limits for each hour
- Response and constraint data
- Whether or not to use start-up and no-load fees

The Network Customer may request Network External Designated transmission service for the delivery of a designated network resource. Requests for service are subject to Available Transmission Capability (ATC) and other PJM Regional Practices (<http://www.pjm.com/markets-and-operations/etools/~media/etools/oasis/regional-practices-clean.ashx>).

Energy Scheduling (EES and eTag) Requirements:

A valid NERC eTag is required for all hours that the external resource will be bid into PJM. The firm OASIS reservation assigned to the external resource shall be linked to the tag. The tag will also have a special exception attached in the form of the Token/Value pair: "EXCEPTION"/"CAPBACK", and the tag will be subject to PJM interchange ramp limits.

6.3.8 Day-ahead Market between 1200 and 1600

As specified in the Energy Market Business Rules, Bidding and Operations Timeline section, all bids must be received by 12:00 noon. From 12:00 noon to 4:00 p.m. (ET), the bids will be evaluated. Results will be posted in the eMKT system at 4:00 p.m. (ET). External Capacity Participants will be required to check the eMKT system to see if the bid has been accepted.

For bids accepted in the Day-ahead Market, External Capacity Participants may submit adjustments to the hourly profile of their tag in order to avoid balancing market MW deviations.

6.3.9 Rebidding Period between 1600 and 1800

If the unit is accepted in the Reliability Run, External Capacity Participants will be required to submit a NERC eTag that matches the hourly energy profile.



If the bid is not accepted in the Day-ahead Market the participant may choose to either modify an already existing tag to zero (0) MW, or take no action.

If the participant wishes to schedule the resource as a self-scheduled/must run unit they may choose to do so and must submit an eTag. The participant must also notify the PJM Generation Dispatcher that the unit is being self-scheduled into PJM as a contract.

6.3.10 Real Time Market

If the bid is not accepted in the Day-ahead Market or Reliability Market, but is requested during the operating day the Generation Dispatcher will notify the participant who will then submit an eTag to match the request. This tag will be subject to all scheduling timing requirements and PJM interchange ramp limits.



Section 7: External Transaction Scheduling

Section Removed: Information regarding External Transaction Scheduling is contained in Manual 41: Managing Interchange



Section 8: Posting OASIS Information

Section Removed: Information regarding Posting OASIS Information is contained in Manual 4: PJM OASIS Operation



Section 9: Hourly Scheduling

Welcome to the *Hourly Scheduling* section of the ***PJM Manual for Energy & Ancillary Services Market Operations***. In this section you will find the following information:

- How schedules may be adjusted on an hourly basis (see “*Hourly Scheduling Adjustments*”).

9.1 Hourly Scheduling Adjustments

During the course of Bulk Electric System operations, planned and unplanned events may continually occur. This section discusses the process by which pre-planned operating schedules may be changed by PJM or PJM Members to reflect new conditions.

A PJM Member may adjust the schedule of a resource under its dispatch control (Self-Scheduled Resource) on an hour-to-hour basis beginning at 2200 of the day before the Operating Day under the following conditions:

- Subject to the right of PJM to schedule and dispatch Self-Scheduled Resources in an Emergency
- Provided that PJM is notified not later than 60 minutes prior to the hour in which the adjustment is to take effect

The following adjustments may be made:

- A PJM Member may self-schedule any of its resource increments, including hydro power resources not previously designated as Self-Scheduled Resources and not selected as a PJM RTO – Scheduled Resource
- A PJM Member may request the scheduling of a new Bilateral Transaction that uses non-firm transmission service
- A PJM Member may remove from service a resource increment, including a hydro power resource that it had previously designated as a Self-Scheduled Resource, provided that PJM has the option to schedule energy from such resource increment at the price offered in the scheduling process, with no obligation to pay any start-up fee

An External Market Buyer may refuse delivery of some or all of the energy it requested to purchase by notifying PJM dispatcher of the adjustment in deliveries not later than 20 minutes prior to the hour in which the adjustment is to take effect. Any such refusal of delivery shall be subject to non-delivery charges as described in the [PJM Manual for Operating Agreement Accounting \(M-28\)](#).





Section 10: Overview of the Demand Resource Participation

Welcome to the Overview of the Demand Resource Participation section of the **PJM Manual Energy & Ancillary Services Market Operations**. In this section you will find the following information:

- An overview description of the Demand Resource Participation in the PJM Energy Market (see “Demand Resource Participation”).
- A list of the Demand Resource Registration Requirements (see “*Demand Resource Registration Requirements*”).
- A list of the Demand Resource Energy Market Participation (see “*Demand Resource Energy Market Participation*”).
- A list of the Demand Resource Metering and Settlement Data Requirements (“*Demand Resource Metering and Settlement Data Requirements*”).

10.1 Overview of Demand Resource Participation

The integration of Demand Response into the PJM Markets recognizes the importance of load response to a fully functioning market as well as the affect of load response on the reliability of the grid. The purpose of these rules is to enable Demand Resources under the direction and control of Curtailment Service Providers to participate in the various PJM markets. Curtailment Service Providers (CSPs) are Members or Special Members of PJM that participate in the PJM Markets by causing Demand Resources to reduce demand.

PJM Emergency Load Response enables Demand Resources that reduce load during emergency conditions to receive payment for those reductions.

- Demand Resources in the Energy Only Option of Emergency Load Response are defined as Demand Resources that receive only an energy payment for reductions.
- Demand Resources in Full Emergency Load Response are defined as Demand Resources that receive both an energy payment for reductions and a capacity payment.
- Demand Resources in Capacity Only Option of Emergency Load Response are defined as Demand Resources that receive only a capacity payment for reduction.

PJM Economic Load Response enables Demand Resources to respond to PJM energy, synchronized reserve, and/or day-ahead scheduling reserve prices by reducing consumption and receiving a payment for the reduction or following PJM signal to reduce or increase load if providing regulation services.



- The **Day-ahead Option** will provide a mechanism by which any qualified market participant may offer Demand Resources the opportunity to reduce the load they draw from the PJM system in advance of real-time operations and receive payments based on day-ahead LMP for the reductions
- The **Real-time Option** will provide a mechanism by which any qualified market participant may offer Demand Resources the opportunity to commit to a reduction and receive payments based on real-time LMP for the reductions.

Energy Settlements shall be limited to demand reductions executed in response to the real-time and/or day-ahead LMP or as dispatched by PJM. -Reductions that do not meet these requirements will not be eligible for settlement.- Examples of ineligible settlements include, but are not limited to the following:

Settlements based on variable demand where the timing of the demand reduction supporting the settlement did not change in direct response to the real-time and/or day-ahead LMP

Consecutive daily settlements that are the result of a change in normal demand patterns that are submitted to maintain a CBL that no longer reflects the relevant end-use customer's demand.

Settlements based on On-Site Generator data if the On-Site Generation is not supporting demand reductions executed in response to the real-time and/or day-ahead LMP

Settlements based on demand reductions that are the result of operational changes between multiple end-use customer sites in the PJM footprint except that settlements based on such demand reduction shall be allowed if the demand reduction alleviates congestion.

PJM shall disallow settlements for demand reductions that do not meet the requirements set forth above. If the CSP continues to submit settlements for demand reductions that do not meet the requirements set forth above then PJM shall suspend the CSP's Energy Market activity and refer the matter to the FERC Office of Enforcement.

10.1.1 Economic Load Response Participant Review Process

PJM shall review the participation of a CSP, EDC and/or LSE in the Energy Market under the following circumstances:

- The CSPs registrations are disputed more than 10% of the time by the relevant EDC or LSE.
- The CSP's settlements are disputed more than 10% of the time by the relevant EDC or LSE.
- The CSP's settlements are denied by PJM more than 10% of the time.

Formatted: PJM_Bulleted_Outline_1



PJM shall have 30 days to conduct the required review. PJM may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant CSP and/or EDC or LSE is engaging in activity that is inconsistent with the Economic Load Response rules.

10.2 Demand Resource Registration Requirements

Curtailment Service Providers shall register Demand Resources that choose to participate in the PJM Energy, Capacity, Synchronized Reserve, Day Ahead Scheduling Reserve or Regulation Market according to the rules and requirements set forth below. A CSP is required to have effective agreement with a customer to register a location.

10.2.1 Registration combinations

One or more CSPs may register the same location (EDC account number) to one or more registrations based on the following conditions:

Scenario	Economic (Energy, SR, DASR, Reg)	Economic (Energy Only)	Economic Regulation Only	Emergency Capacity Only	Emergency Full (Capacity and Energy)	Emergency Energy Only
CSP1	Yes	na	na	No	Yes	No
CSP1	Yes	na	na	Yes	No	Yes
CSP1	Yes	Na	Na	No	No	Yes
CSP2	No	na	na	Yes	No	No
CSP1	No	No	Yes	No	No	No
CSP2	No	Yes	No	No	Yes	No
CSP1	No	Yes	Yes	No	No	Yes
CSP2	No	No	No	Yes	No	No
CSP1	No	No	Yes	No	No	No
CSP2	No	Yes	No	No	No	Yes
CSP3	No	No	No	Yes	No	No

Formatted: PJM_Normal, None

Formatted: PJM_Normal, None



Economic (Energy, SR, DASR, Reg) – registration will allow participation in the energy market and ancillary service market(s) if certified and approved by PJM.

Economic (Energy Only) – an economic registration that only allows participation in the Energy market. This is normally used when 1 economic CSP has an Economic Regulation Only registration and the second economic CSP has the Economic (Energy Only) registration .

Economic Regulation Only – registration that only allows participation in the regulation market.

Emergency Capacity Only – registration that only allows participation in capacity market as an RPM or FRR capacity resource. If the registration is dispatched for emergency conditions the resource will not receive an energy payment.

Emergency Full (Capacity and Energy) – same as Capacity Only registration but receives emergency energy compensation when dispatched for emergency conditions.

Location that registers with one CSP for Emergency Full can register with second CSP only for Economic Regulation-Only

Location that registers with one CSP for Emergency Capacity Only can register with second CSP for:

- Economic (Energy, SR, DASR, Reg) or;
- Economic (Energy Only) and/or,
- Economic Regulation Only

Formatted: Bulleted + Level: 1 + Aligned at: 0.25" + Indent at: 0.5"

Formatted: PJM_Normal, None, Bulleted + Level: 1 + Aligned at: 0.25" + Indent at: 0.5"

Formatted: PJM_Normal, None

Location that registers with one CSP for Emergency Capacity Only, and with second CSP for Economic Regulation Only, can also register with third CSP for Economic (Energy Only)

10.2.42 Curtailment Service Providers

The following business rules apply to Curtailment Service Providers:

- Prior to participating in the PJM Markets, Curtailment Service Providers must complete a registration in the appropriate PJM eSuite application which identifies the specific location(s) based on the unique EDC account number that will participate and their associated load reduction capability. Curtailment Service Providers shall maintain the accuracy of the registration information provided to PJM for each demand resource.



- ~~— Simultaneous registration of a ~~d~~Demand ~~e~~Resource by more than one Curtailment Service Provider will not be accepted by PJM unless the registration by one CSP is for an ~~Emergency~~ Capacity-Only ILR or Capacity-Only DR resource and the other registration is for economic participation.~~
- In order to register ~~d~~Demand ~~re~~Resources all specific information as defined in the eLRS User Guide shall be provided. Economic and Emergency registration must have the same EDC, LSE, Transmission zone and Pricing point where each location is defined as a unique EDC account number and may be included on the registration subject to aggregation rules in this manual. Economic Regulation Only registration must have the same EDC and Transmission zone.
- If CSP has Economic Regulation Only -registration then Economic registration will only allow same location(s) to participate in energy market (“Economic (Energy Only)” in chart above) and they will not be permitted to participate in the SR or DASR market.
- If CSP has Economic registration with any certified ancillary service (SR, DASR or Reg) then Economic Regulation Only registration may not be submitted.
- Econ Regulation Only CSP must be able to manage regulation for location whether or not the location has been called to provide capacity during an emergency situation or is providing a load -reduction as an economic resource in the energy market.
- Economic demand resource registration may be associated with a ~~d~~dispatch ~~g~~group. The dispatch group will allow the Curtailment Service Provider to have one real time or day ahead energy market bid for the entire dispatch group.
- The dispatch group must have the registrations with the same Transmission Zone and energy market pricing point.
- Registrations that participate in ancillary service markets will not be permitted to use a dispatch group unless approved by PJM.
- Registration cannot be in a ~~D~~dispatch ~~G~~group and as a standalone registration. This will ensure that each registration is only available to bid once in the market and avoid duplications.
- Registrations must be confirmed before they may be added to a ~~D~~dispatch ~~G~~group.
- Registration that clears in Day Ahead market is not allowed to be assigned to dispatch group on same day it cleared in Day Ahead market. If CSP does try to assign to dispatch group on such day then PJM will remove (because this may create conflict between single registration that cleared in Day Ahead market and dispatch group that may be dispatched in real time market for same Operating Day)



- The CSP is responsible for ensuring that at least 1 registration is in a dispatch group when bid in the Day Ahead or Real Time energy market through the appropriate PJM system.
- Demand Resources may be registered simultaneously as Economic Load Response Resources and Emergency Load Response Resources ~~so long as they bid their economic load reductions in the Day-ahead Market, self-schedule or notify PJM that their demand resources are dispatchable in Real-Time.~~
- Demand Resources may switch CSPs. The CSP registering the switching Demand Resource shall provide PJM with the name of the CSP that previously registered the Demand Resource. PJM will treat the switching as a new registration and will request the CSP that previously registered the Demand Resource to terminate the previous registration. PJM will deem the previous registration terminated if the previous CSP does not respond within 10 business days. Termination of the previous registration will be required for acceptance of the switched registration. No Demand Resource will be eligible to reduce load when the identity of the CSP is in dispute. In order to accommodate day-ahead load response the switch will become effective at 12:01 a.m. of the third business day after the previous registration is terminated or deemed terminated by PJM. The previous registration will remain active for the sole purpose of settlement of load reductions that occurred before the switch became effective.
- Demand Resource intending to run an On-Site Generator in support of local load represents to PJM that it holds all applicable environmental and use permits for running those generators by submitting a registration. Continuing participation will be deemed as a continuing representation by the owner that each time its On-Site Generator is run it complies with all applicable permits, including any emissions, run-time limit or other constraint on plant operations that may be imposed by such permits.
- To assist CSPs in obtaining the electric usage information of the end-use customer the following Customer Usage Information Authorization form has been developed.



|



**Customer Usage Information Authorization
for PJM Load Response Programs (“Authorization”)**

_____, the end-use customer, (“Customer”) hereby authorizes _____, and _____, its electric distribution company(ies) (“EDCs”), to release its electric usage information, including hourly or sub-hourly usage history (kWh/kW), EDC loss factors, and peak load contribution assignments for the current delivery year and the upcoming delivery year, if known, to _____, the curtail service provider (“CSP”), which has been or may be retained by Customer to act on its behalf in the PJM Load Response Programs. Customer’s EDCs and end-use sites are identified on Attachment A-1 and A-2 hereto, which are incorporated herein by reference.

- 1. Customer’s contact information for purposes of its participation in the PJM Load Response Programs is as follows:

Customer Name: _____

Contact Person: _____

Mailing Address: _____

City

State

Zip Code



Telephone Number: _____

Fax Number: _____

Contact Person's Email Address: _____

2. Customer hereby advises CSP that it deems the information obtained pursuant to this Authorization to be confidential and therefore requests that such information not be divulged to any third party, except as required to participate in the PJM Load Response Programs.

3. This Authorization shall terminate as follows (mark ONE of the options below):

____ This Authorization shall be perpetual and shall not terminate unless written notice is provided to CSP at least ____ days in advance.

____ This Authorization shall automatically terminate on _____, with no further notice to CSP being required.



4. I understand that termination of this Authorization will not affect any action that CSP took in reliance on this Authorization before it automatically terminated or before CSP received Customer's written notice of termination.

5. The undersigned affirms that he/she has authority to execute this Authorization on behalf of Customer.

IN WITNESS WHEREOF, Customer executes this Authorization to be effective as of the date written below.

Customer: _____

By: _____

Print Name

Title

Signature

Date





ATTACHMENT A-1

LIST OF SITES FOR WHICH EDC, _____, HAS AUTHORIZATION TO
PROVIDE ELECTRIC USAGE INFORMATION TO CSP

Account Number(s):

Service Address:

Account Number(s):

Service Address:

Account Number(s):

Service Address:

Account Number(s):

Service Address:





10.2.23 PJM Activities

The following business rules apply to PJM activities:

- PJM will, ~~as necessary if appropriate~~, propose ~~or determine~~ an alternative CBL calculation together with supporting analysis. The process for determining ~~the appropriate an alternative~~ CBL is set forth below.
- PJM will confirm with the appropriate Load Serving Entity (LSE) and Electric Distribution Company (EDC) whether the load reduction is under other contractual obligations. (The EDC and LSE have ten (10) business days to respond or PJM assumes acceptance.)
- Other contractual obligations may not preclude participation, but may require special consideration by PJM such that appropriate settlements are made within the confines of the existing contract.
- ~~PJM will confirm with the customer's LSE whether the Demand Resource is served under day-ahead or real-time LMP-based contract for energy delivery. PJM will further verify the nature of the Demand Resource's LMP-based contract.~~
- ~~An LMP-based contract is defined as one by which an end-use customer has agreed to pay its LSE for the physical delivery of energy according to the hourly value of the Locational Marginal Price (LMP) as calculated by PJM. The bus, zone, aggregate, etc at which the LMP forms the basis for the contract is immaterial. The LMP on which the contract is based can be either day ahead or real-time, and is assumed to be some multiple of the actual, calculated LMP.~~
- ~~End use customers that have LMP-based contracts under which they have agreed to pay their Load Serving Entity (LSE) for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM may participate in the Real-time Market as provided for under the Real-time Operations section below.~~
- ~~PJM will verify the transmission and generation (retail rate) charges with the appropriate LSE.~~
- ~~PJM will verify whether or not a Demand Resource is subject to a Load Management contract. PJM will further verify the nature of the Demand Resource's Load Management contract.~~
- ~~If a Load Response registration is denied by an EDC or LSE because the Curtailment Service Provider provided an incorrect EDC Account Number, Zone, Aggregate or Retail Contract Information; the Curtailment Service Provider must submit to PJM a new registration for the Demand Resource that includes the correct EDC Account Number,~~



~~Zone, Aggregate and Retail Contract Information, unless the registration is corrected by the EDC or LSE.~~

~~— If a Load Response registration or re-registration is reviewed by an EDC or LSE and the EDC or LSE does not believe that the standard CBL calculation is appropriate, then the EDC or LSE shall provide a proposed alternative CBL calculation together with supporting analysis to PJM, the CSP, and the EDC or LSE respectively. The process for determining the appropriate CBL is set forth below.~~

- ~~• PJM will inform the CSP, EDC and LSE Curtailment Service Provider of the demand resource's acceptance into the program as appropriate.~~
- PJM will create LSE negative DEC bids for DR that clears in DA market for dispatch group based on registration DR load reduction capability. PJM will create LSE negative DEC bids for DR that clears in DA market for registrations based on amount that cleared in DA market.

Formatted: Not Highlight

•

~~— PJM will notify the appropriate LSE and EDC of the Demand Resource's acceptance.~~

~~— Curtailment Service Providers shall maintain the accuracy of the registration information provided to PJM for each Demand Resource.~~

10.2.34 Electric Distribution Company ("EDC") and Load Serving Entity ("LSE") activities

- ~~• EDC will have 10 business days to review the all registrations and verify the EDC account number, Zone, Pricing point, Line losses, existence of EDC interval meter if applicable, accuracy of peak load contribution (PLC), and whether or not the customer may or may not participate based on the Relevant Electric Retail Regulatory Authority orders, ordinances or resolutions. If the information provided by the CSP is incorrect the EDC may deny the registration. Once the registration is denied the CSP may correct the inaccurate information and resubmit the registration.~~
- ~~• LSE will have 10 business days to review registrations except the Economic Regulation Only registration and verify whether or not the customer may or may not participate based on the Relevant Electric Retail Regulatory Authority orders, ordinances or resolutions and if the customer. LSE will also review registration to determine if the load reduction for the location(s) are subject to an LSE contractual obligation. If the information provided by the CSP is incorrect the LSE may deny the registration. Once the registration is denied the CSP may correct the inaccurate information and resubmit the registration.~~



10.2.345 CBL Certification Process

- All Economic registrations, except Economic Regulation Only registrations, should go through the CBL certification process to ensure that the CBL used to predict the customer load and therefore determine the quantity of each hourly load reduction- is reasonably accurate and non-biased. All registrations should use a CBL with a relative root mean square error ("RRMSE") no greater than 20% unless otherwise approved by PJM. PJM, the CSP, the EDC, and/or the LSE that proposes an alternative CBL calculation shall provide the alternative CBL calculation and supporting analysis to the other parties. Registrations with a RRMSE greater than 20% based on hourly load data provided ins the registration process are considered variable- load customers.
- CBL certification is performed by the CSP prior to registration submission. CSP should always calculate an RRMSE for the standard CBL defined in the tariff. An alternative CBL may be requested if the alternative CBL is more accurate than the standard CBL and has an RRMSE less than or equal to 20%. The primary purpose for the use of an alternative CBL is to create an accurate CBL for variable load customers that can be administered on a consistent basis across the PJM market.
- The RRMSE will be based on 60 most recent days of contiguous hourly load data where the most current load data should be 60 days or less than the date the RRMSE is calculated unless otherwise approved by PJM.
- PJM ~~and, the~~ CSP, ~~the EDC and the LSE~~ shall have 30 days from the day the alternative CBL proposal is received by ~~the other parties~~ to agree on a proposed alternative CBL calculation. If the parties agree on an alternative CBL calculation, then the agreed upon CBL calculation shall be effective from the date of the registration.
- If ~~PJM and CSP the parties~~ do not agree on an alternative CBL calculation within 30 days, then PJM shall determine the CBL calculation within 20 days of the expiration of the prior 30 day period. The CBL established by PJM shall be binding on the parties unless agreement on an alternative CBL is reached before the end of the 20 day period.
- The process for determining the appropriate CBL shall not delay the registration, provided that the alternative CBL established shall be used for all applicable energy settlements.
- PJM shall periodically publish herein alternative CBL calculations established through this process.
- Relative Root Mean Squared ERROR (RRMSE) calculation is performed as follows unless otherwise approved by PJM:
 - To perform the RRMSE calculation, daily CBL calculations are first performed for the CBL method using hours ending 14 through hours ending 19 unless otherwise approved by PJM as the simulated event hours for each of the 60 non-event days according to the CBL method rules.

Formatted: Highlight

Formatted: PJM Bullet 2



- o Actual Hourly errors are calculated by subtracting the CBL hourly load from the actual hourly load for each of the simulated event hours of the non-event day.
- o The Mean Squared Error (MSE) is calculated by summing the squared actual hourly errors and dividing by the number of simulated event hours.
- o The Average Actual Hourly Load is the average of the actual hourly load for each of the simulated event hours.
- o The Relative Root Mean Squared Error (RRMSE) is calculated by taking the square root of the MSE then divide that quantity by the average of the actual load.

10.3 Economic Energy Market Participation

Qualified Curtailment Service Providers may offer the load reductions of dDemand rResources into the Day-ahead and/or Real-time Energy Market pursuant to the PJM Manuals, eMKT User Guide, and the following rules and requirements.

Curtailment Service Provider that would like to participate in the Energy market shall submit a bid for each demand resource (registration or dispatch group) which includes:

- Transmission zone and pricing point based on where the demand resource is located and the associate pricing point used to settle the load in the retail market and as defined by PJM.;
- Demand resource bids will be designated by the Market Participant in onmarket type which determines how the bid will be utilized by the Energy Markets of the following 3 ways for each market type will be handled as follows:
 - o Day-Ahead Market – If hour clears in Day Ahead market then demand resource should respond with associated MWs. PJM will not dispatch in Real Time for hours that clear in Day Ahead market.
 - o Real Time Market (Balancing) – demand resource should follow the Real Time dispatch signal for the MW that have been dispatched

Both

Formatted: PJM_Normal Char Char1

Formatted: PJM_Bulleted_Outline_1

Formatted: PJM Bullet 2

Formatted: PJM Bullet 2, Indent: Left: 1"



- If specific hour clears in Day Ahead market then demand resource should respond with associated MWs. PJM will not dispatch in Real Time market for hours that clear in Day AheadA market.
- If hour does not clear in Day Ahead market then hour is eligible to be dispatched in Real Time market.
- Incremental Offer curve (minimum increments of 0.1MW) that represents up to 10 combinations of MW load reduction and offer price. This determines the price offered into the Day Ahead market for respective MW amount in each hour and the price offered for dispatch in the Real Time market.
- -Hourly availability which determines the specific hours when the demand resource may be cleared in the Day Ahead Market and the associated MW volume that is available to clear for each hour. This also determines the specific hours when the demand resource may be dispatched in the Real Time market and the associated MW volume that may be dispatched for each hour.
- Economic Min and Max MW used to determine the dispatch of demand resources in the Real Time Energy Market can be changed up to 3 hours before the operating hour by the CSP. For example, hourly updates for HE 15 which starts at 2pm can be changed up to 10:59am during the same day.
- Shut down costs, for each period. The default will be zero if not submitted. Shutdown cost will be expressed in dollars, and represents the fixed cost associated with committing a load response resource. Shutdown costs will be changeable only every six months, corresponding to the six-month periods during which price-based start-up costs may be changed for generators. The six month periods for shutdown costs are defined as follows: Period 1 is defined as April 1 – September 30 and Period 2 is defined as October 1 - March 30.
- Minimum down times for which the load reduction must be committed. The default will be zero if not submitted. Minimum down time will be expressed as a number of hours, and represents the minimum number of contiguous hours for which a load response bid must be committed in the Day-ahead Market or dispatched in Real Time Market.
- The specific hours when the demand resource would like to be cleared in the Day Ahead Market or the hourly Econ Min and Econ Max MW availability for the demand resource to be dispatched in the Real Time Market.
- Load Response bids in the Day Ahead market or hourly MW availability in the Real Time market should exclude losses (transmission zone losses and share of 500 kV losses). This means bids should be based on expected retail metered load reductions grossed up for line losses.

Formatted: PJM Bullet 3



Day Ahead Energy Market bids and associated information must be submitted based on overall Energy Market rules and associated time line as described in this manual.

Formatted: PJM_Bulleted_Outline_1

10.3.1 Day-ahead Operations

Formatted: PJM_Normal

~~Demand Resources, except Demand Resources served under LMP-based contracts that provide for payment for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, have the option to participate in the Day-ahead Market. Participants in Economic Load Response Program may submit a bid to reduce the load they draw from the PJM system in advance of real-time operations. In the Day-ahead Market, the participant may submit a Load Response Bid on behalf of a Demand Resource ("Load") for a specific KW curtailment (in minimum increments of .1 MW or 100 KW). Participants that submit Load Response bids in the Day-ahead Market may establish an incremental offer curve.~~

~~Demand Resources that are served under LMP-based contracts that provide for payment for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, do not have the option to participate in the Day-ahead Market.~~

~~Each Market Participant's registration shall specify the transmission zones or aggregates for which that Participant is eligible to submit load response bids.~~

~~Load Response bid offers Bids should are assumed to exclude losses (transmission zone losses and share of 500 kV losses). This means bids should be based on expected retail metered load reductions grossed up for line losses.~~

~~The Load Response bid offer Bid may could also include for each Demand Resource:~~

- ~~○ Shut down costs, for each period. The default will be zero if not submitted.~~
- ~~○ Minimum down times for which the load reduction must be committed. The default will be zero if not submitted.~~
- ~~○ Shutdown costs and minimum down times are optional, and will default to zero (0) if not submitted.~~

Formatted: PJM_Normal, No bullets or numbering



Shutdown cost will be expressed in dollars, and represents the fixed cost associated with committing a load response resource.

Shutdown costs will be changeable only every six months, corresponding to the six month periods during which price-based start-up costs may be changed for generators.

The six month periods for shutdown costs are defined as follows: Period 1 is defined as April 1 – September 30 and Period 2 is defined as October 1 – March 30.

Minimum down time will be expressed as a number of hours, and represents the minimum number of contiguous hours for which a load response bid must be committed in the Day-ahead Market.

If a Market Program Participant submits no day-ahead bid information, then a zero KW quantity is assumed.

The list of transmission zones and aggregates for which Load Response Bids are accepted is defined by PJM.

All day-ahead Load Response Bids will be submitted to the eMKT Web site by noon each day and in accordance with the day-ahead market rules.

The Day-ahead Market closes at 1600 each day, and cleared Load Response Bids will be posted to eMKT.

10.3.2 Real-time Operations

~~Demand Resources including Demand Resources served under LMP-based contracts that provide for payment for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, have the option to participate in the Real-time Energy Market. Demand resources do not have to bid in the Day Ahead Energy market to participate in the Real-time Energy market. Curtailment Services Providers, representing Demand Resources participating as Economic Load Response resources, may choose to commit to a reduction of the load they draw from the PJM system when they are dispatched by PJM during times of high prices. These Curtailment Service Providers are responsible for determining the conditions under which load reductions will actually take place and implementing the reductions should those conditions arise.~~

~~Demand Resources served under LMP-based contracts that provide for payment for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM, have the option to participate in the Real-time Market under the following circumstances. The Curtailment Service Provider shall provide PJM with a “strike” price for the Demand Resource’s zonal LMP at which the Demand Resource will reduce load, as well as any shutdown costs and opportunity costs and costs associated with the minimum number of contiguous hours for which the load reduction must be committed.~~

Formatted: PJM_Normal



~~Each Curtailment Service Provider may submit an incremental offer curve in the Real-time energy market.~~

~~PJM will dispatch economic demand response resources based on their bid information and expected system condition through the security constrained economic dispatch algorithm. Demand resources dispatched by PJM will be paid based on the load reductions achieved and the applicable real-time LMP and in accordance with Manual 28. In cases where the applicable zonal real-time LMP reaches the “strike” price and the load response is dispatched by PJM, PJM shall pay the CSP the difference between the actual savings achieved based on zonal LMP and the total value of the load response bid, if savings achieved by the load reduction are less than the total value of the load response bid. For purposes of this provision, the load response bid will be the sum of the “strike” price times the MW of reduction achieved during each hour of the time period the reduction was dispatched by PJM or minimum down-time whichever is greater, plus submitted shutdown costs.~~

~~Each Curtailment Service Provider may submit an incremental offer curve, or self-schedule in the Real-time energy market.~~

~~If a Load Response Bid for a Demand Resource is not accepted in the Day-ahead Market and the CSP indicates that it wishes the Demand Resource to be dispatchable in real-time, PJM will use the incremental offer curve and operational information to dispatch the Demand Resource in real-time. PJM shall not dispatch a Demand Resource that has already self-scheduled. In the event that a Demand Resource that has been self-scheduled is also dispatched by PJM then settlement will be based on the Notification of self-schedule.~~

~~Curtailment Service Providers shall provide PJM with Notification no less than 5 minutes prior to beginning a load reduction event and no more than 7 days prior to an event. CSPs may begin a Demand Response intra-hour provided that Notification is given. A Notification may be withdrawn or adjusted downward during the relevant event hour, but not after the event hour. The Notification shall include the start and stop times of the event and the amount of the demand reduction. PJM will provide the Notification window(s) to the LSE as part of the settlement approval process. In the event that the Load Resource fails to reduce load and the CSP does not submit a settlement, no payment or debit will be assessed by PJM. Notification must be given when the CSP will submit a settlement for an energy payment when the load reduction complies with a synchronized reserve event or a regulation assignment.~~

~~Demand Resources will not be eligible to set Day Ahead and Real Time Energy market prices if selected as the marginal resource, real-time price on the PJM system unless metered directly by PJM.~~

Formatted: PJM_Normal, Space After: 0 pt, Line spacing: single

Formatted: PJM_Normal



10.3.1 Net Benefits Test to determine Net Benefits Threshold

The Net Benefits Threshold is the point on the aggregate supply curve at which the participation of Demand Response Resources results in a greater overall savings to the load on the system compared to the Demand Response Resources remaining on the system as load. PJM shall compute the Net Benefits Threshold monthly as described below. PJM shall post the Net Benefits Threshold and associated supporting information for each month by the 15th of the prior month on pjm.com. CSP will only receive compensation for demand resources cleared in day ahead market or dispatch by PJM in the Real Time market if the applicable LMP is greater than or equal to the monthly NBT.

The Net Benefits Test is executed using the following steps:

Step 1: Retrieve generation offers from the same calendar month of the prior calendar year for which the calculation is being performed. These generation offers will use market-based price offers to the extent available, and cost-based offers to the extent market-based price offers are not available.

Note: To the extent that generation offers are unavailable from historical data due to the addition of a Zone to the PJM Region, PJM shall use the most recent generation offers that best correspond to the characteristics of the calendar month for which the calculation is being performed, provided that at least 30 days of such data is available. If less than 30 days of data is available for a resource or group of resources, such resource[s] shall not be considered in the Net Benefits Test calculation.

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the PJM Region for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. To accomplish this adjustment, spot fuel prices for the reference month will be compared to forward prices for the study month. First, the spot prices for representative PJM fuels will be averaged together for the reference month.

For natural gas, the Henry Hub price is used, since natural gas prices tend to move in concert with Henry Hub. For oil, the New York Harbor price for No. 2 fuel oil is used. For coal adjustments, PJM has determined a mix of 20% Powder River Basin, 50% Northern Appalachia, and 30% Central Appalachia coal to be representative of the fuel used by PJM resources. Representative coal prices will be combined in a weighted average to form a representative RTO coal price for the reference month.

Forward prices will be used to determine a similar representative price for the study month. These two values will be used as a ratio. If the representative price from June 2010 was \$4.10, and the



forward price for June 2011 was \$4.51, then the ratio would be 1.1 (prices were up 10%, or June 2011's price is 110% of June 2010's price.)

The offers of generation units will then be adjusted by this scaling factor. The price of fuel typically represents 80 to 90 percent of a generator's offer with the remainder being variable operations and maintenance costs and other uncertainties. As such, 85 percent of each generator's offer will be scaled by the fuel scalar.

Where generators offer multiple points on a curve, each point on the curve is adjusted in this manner.

Step 3: Combine the offers to create daily supply curves for each day in the period.

Step 4: Average the daily curves for each day in the month to form an average supply curve for the study month.

Step 5: Use a non-linear least squares estimation technique to determine an equation that reasonably approximates and smoothes the average supply curve. PJM shall publish the details of the equation and parameters each month along with the Net Benefit Threshold results.

Step 6: Determine the net benefit level as the point at which the price elasticity of supply is equal to 1 for the estimated supply curve equation established in Step 5.

The event period for self-scheduled Demand Resources shall be defined as all hours in the day for which the CSP has provided a Notification. If Notification and settlement hours do not match, then a review of the CSP's settlements for up to the 12 prior months by PJM to determine free-ridership will be triggered.

10.4 Demand Resource Metering and Settlement Data Requirements

The settlements submitted to PJM by Curtailment Service Providers must conform to the following requirements for data, including metered data, and Customer Baseline Load (CBL) calculations. All settlement related calculations for economic and emergency demand resources are provided in Manual 28.



10.4.1 Metered Data

- For load reduction that is not metered directly by PJM, Curtailment Service Providers are responsible for forwarding the appropriate meter data (as defined in this Manual) to PJM within 60 days of the reduction. Participants submitting a settlement for an energy payment when load reduction complies with a synchronized reserve event or regulation assignment must use data provided by the load meter. This data shall be forwarded through the appropriate PJM system Load Response.
- If the meter data files are not received within 60 days, no payment for participation is provided.
- ~~MeterLoad~~ data must be provided for all hours of the day and for all days necessary for PJM to calculate the CBL for settlements or to measure compliance as necessary, the hour prior to the reduction, as well as every hour during the reduction with the following exception.
- When on-site generation is used solely to enable the Participant to provide demand reductions then the CSP may provide qualified meter generation output data, upon approval by PJM, from the on-site generation for each hour of the event day instead of actual load metered data. Provision of hourly meter data from the on-site generation will be deemed a certification by the CSP that the on-site generation was not used for any purpose other than to support the load reduction during the event day. If the On-Site Generator is used on a regular basis for normal operations then the CSP may provide qualified meter data from the On-Site Generator for each hour of the event provided the amount of generation run to provide Economic Load Response can be quantified in a manner that is acceptable to PJM. For example, if a 5 MW On-Site Generator that normally provides 3 MW boosts its output to 5 MW in response to LMPs the CSP will be eligible to receive a demand response energy settlement for the additional 2 MW of output.
- Meter data will be forwarded to the EDC and LSE upon receipt, and these parties will then have ten (10) business days to review accuracy and provide feedback to PJM.
- Objection by the EDC or the LSE to ~~the CBL, the Meter Data, or the retail rate~~ shall be clearly set forth in the Comments related to the Settlement Data. The CSP shall correct and re-submit the Settlement Data within 2 business days. The objecting EDC and/or LSE shall have 5 business days to review the re-submitted Settlement Data or PJM will assume acceptance.
- All load reduction data are subject to PJM Market Monitoring Unit audit.

10.4.2 Customer Baseline Lineoad (CBL)

The following tables list all available CBLs and represent the different parameters used for each calculation. The 3 Day Type with SAA (symmetric additive adjustment) represents the



default standard, tariff defined CBL which is utilized for most Non-Variable economic demand resources and is set forth in section 3.3A.2 of the PJM tariff. The alternative CBLs on the list have been created over time to provide options, especially for Variable Load customers that have an RRMSE above 20%.

Curtailment Service Providers are responsible for forwarding the appropriate CBL data (to PJM within 60 days of the reduction.

If the CBL data files are not received within 60 days, no payment for participation is provided.

PJM will make available the Customer Baseline (CBL) calculations to the appropriate EDC and LSE for optional review.

The CSP shall inform PJM, of any significant change to the demand resource's operations that increases or decreases the demand resource's CBL. A significant incremental change is defined as any operational or physical change to the demand resource's facilities that will adjust more than half the hours in the demand resource's CBL by at least 20% for more than twenty consecutive days. PJM may require and approve such adjustments to the CBL as are necessary to reflect the significant incremental change.

All CBL data are subject to PJM Market Monitoring Unit audit.

Formatted: PJM_Normal

Formatted: Default Paragraph Font



Parameter/CBLs	3 DayTypes		3 Day Types with SAA (Tariff Default)		3 Day Types with WSA	
	Weekdays,	Sat ,Sun/Hol	Weekdays	Sat,Sun/Hol	Weekdays	Sat, Sun/Hol
DayType	Weekdays,	Sat ,Sun/Hol	Weekdays	Sat,Sun/Hol	Weekdays	Sat, Sun/Hol
Calculation¹	Average	Average	Average	Average	Average	Average
CBL Basis Window²	5	3	5	3	5	3
CBL Basis Window Limit³	45	45	45	45	45	45
Start Selection From Days Prior to Event⁴	1	1	1	1	1	1
Exclude Previous Curtailment Days⁵	Y	Y	Y	Y	Y	Y
Exclude Long/Short DST Days⁶	N/A	Y	N/A	Y	N/A	Y
Exclude Avg. Event Period Usage Less than Threshold⁷	25%	25%	25%	25%	25%	25%
Exclude # of Low Usage Days⁸	1	1	1	1	1	1
Use Previous Curtailment if CBL Basis Window incomplete⁹	Yes	Yes	Yes	Yes	Yes	Yes
Use Highest or Recent Previous Curtailment Day¹⁰	Highest	Highest	Highest	Highest	Highest	Highest
Adjustments¹¹	None	None	Symmetric Additive	Symmetric Additive	Weather Sensitive	Weather Sensitive
Allow Negative Adjustments¹²	N/A	N/A	Yes	Yes	Yes	Yes
Adjustments Start (HE0-x)¹³	N/A	N/A	4	4	0	0
Adjustment Basis Hours¹⁴	N/A	N/A	3	3	Event Hours	Event Hours



Parameter/CBLs	7 DayTypes Mon,Tue,Wed,Thu,Fri,Sat, Sun/Hol	7 Day Types with SAA Mon,Tue,Wed,Thu,Fri,Sat, Sun/Hol	MBL(Max Base Load) ^A		Metered Generation ^B
			Weekdays	Sat,Sun/Hol	
DayType					N/A
Calculation ¹	Average	Average	Average	Average	N/A
CBL Basis Window ²	3	3	5	3	N/A
CBL Basis Window Limit ³	60	60	45	45	N/A
Start Selection From Days Prior to Event ⁴	1	1	1	1	N/A
Exclude Previous Curtailment Days ⁵	Y	Y	Y	Y	N/A
Exclude Long/Short DST Days ⁶	Y	Y	N/A	Y	N/A
Exclude Avg. Event Period Usage Less than Threshold ⁷	25%	25%	25%	25%	N/A
Exclude # of Low Usage Days ⁸	0	0	0	0	N/A
Use Previous Curtailment if CBL Basis Window incomplete ⁹	Yes	Yes	Yes	Yes	N/A
Use Highest or Recent Previous Curtailment Day ¹⁰	Highest	Highest Symmetric Additive	Recent	Recent	N/A
Adjustments ¹¹	None		None	None	N/A
Allow Negative Adjustments ¹²	N/A	Yes	N/A	N/A	N/A
Adjustments Start (HE0-x) ¹³	N/A	4	N/A	N/A	N/A
Adjustment Basis Hours ¹⁴	N/A	3	N/A	N/A	N/A

Notes:

MBL(Max Base Load).- The MBL CBL for weekdays shall be the average of the daily minimum hourly loads during the event hours over the 5 most recent weekdays preceding the load reduction event within the 45 calendar day period preceding the load reduction event. The daily minimum load calculation must be based on a minimum of three hours.- If the number of event hours is less than three, then the daily minimum load calculation will use the following hours of the same calendar day: hour prior to event, event hour(s), hour after event, in that order until three hours are attained. Exceptions: use only event hours in same calendar day if start of event is sometime between 9pm and midnight OR if end of event is sometime before 3am.

Formatted: No bullets or numbering



Metered Generation. -The use of this methodology must be approved by PJM.- Historical data will be required showing that the unit does not normally run or is not normally active.- If the data indicates that the unit runs normally, is active, or if the unit is a cogen operation then another CBL methodology may be required to ensure economic dispatch activity is isolated from normal operations.

Formatted: No bullets or numbering

Calculation. Whether to use median or average to calculate the CBL after the CBL Basis Window has been defined and high and low usage days have been excluded.

Formatted: No bullets or numbering

CBL Basis Days. This is the set of days that will serve as representative of end-use customer's typical usage. If the number of days specified is 5, then after all exclusions (e.g.: before excluding event days and Low Usage Days), the set will contain 5 days.

Formatted: No bullets or numbering

CBL Basis Day Limit. Limit on number of historical calendar days used to select the CBL Basis Days (e.g.: If 45 this means CBL days must be selected from prior 45 calendar days). This ensures recent information is used to predict future consumption.

Formatted: No bullets or numbering

Start Selection from Days before Event Day. Determines most recent historic CBL day to select (e.g. if 1 then select most recent day with same daytype, if 2 then skip most recent day with same daytype and select next day with same daytype)

Formatted: No bullets or numbering

Exclude Previous Curtailment Days. If this is set to "Y", exclude all previous curtailment days. Previous Curtailment Days are previous economic settlements days that include at least 1 hour in pending or confirmed status.

Formatted: No bullets or numbering

Exclude Long/Short DST Days. If this is set to "Y", then any long/short DST day is excluded from the CBL Basis Window.

Formatted: No bullets or numbering

Exclude Avg. Daily Event Period Usage Less than Threshold. If the Average Daily Event Period Usage for the CBL day selected is less than the threshold indicated, then that day will be excluded from the CBL Basis Window.

Formatted: No bullets or numbering



Exclude # of Low Usage Days. If the CBL Basis Days is set to 5 and this switch is set to 1, then the 1 day with the lowest Average Daily Event Period Usage will be excluded from the CBL calculation.

Formatted: No bullets or numbering

Use Previous Curtailment Day if CBL Incomplete. If this is set to "Y", and if the CBL is unable to attain the minimum number of days required to calculate the CBL, then Previous Curtailment Days will be used as CBL Basis Days until such minimum is attained. If this is set to "Y", then Exclude Previous Curtailment Days must also be set to "Y".

Formatted: No bullets or numbering

Use Highest or Recent Previous Curtailment Day. Required if the Use Previous Curtailment Day if CBL Incomplete is set to "Y". "Highest" means that the model will rank Previous Curtailment Days based on event period usage within the CBL Basis Day Limit and add them to the CBL Basis Days in descending order until the CBL Basis Days contains the minimum number of days required to calculate CBL. "Recent" means that the model will start adding days to the CBL Basis Days starting with the Most Recent Curtailment Day that was excluded until the CBL Basis Days contains the minimum number of days required to calculate CBL.

Formatted: No bullets or numbering

Adjustments. Symmetric Additive Adjustment is CBL average usage for Event Day divided by Adjustment Basis Hours for same hours. Weather Sensitivity Adjustment compares difference in average weather over CBL days to weather on event day and then calculates adjustment based on weather sensitivity as described in this manual.

Formatted: No bullets or numbering

Allow Negative Adjustments. If this is set to "Y", then the Adjustments may be positive or negative. Otherwise, Adjustments will always be greater than zero.

Formatted: No bullets or numbering

Adjustment Start (HE0-x). The starting point for the hour(s) to be used in calculating the Adjustments. If the event starts with HE13 and Adjustment Start is 4, then HE9 will be the first hour used to calculate Adjustments.

Formatted: No bullets or numbering

Adjustment Basis Hours. Determines total number of hours to use in the adjustment from the Adjustment Start. If the event is on HE13, Adjustment Start is 4, and Adjustment Basis Hours is 3, then the adjustment will be based on the load from HE9-HE11.

Formatted: No bullets or numbering

Weather Sensitive Adjustment



The WSA Factor Method adjusts the hourly CBL (up or down) to compensate for the average hourly temperature differences between the CBL basis days and the temperature of the event hour.

The WSA Factor represents the kW change in load for each degree of temperature change within a specified temperature range. The WSA factor is the slope of the line that describes the load and temperature relationship at the customer site between two temperature set points. The WSA Factor or slope of the line is obtained by performing a linear or piecewise linear regression analysis on the load and temperature data from the customer site. There should be at least two years of data used in the linear regression analysis to indicate the normal operation of the facility. Exceptions may be granted by PJM to use less data in cases where the normal operations have changed significantly between years. The analysis data should only include the day types and hours where load reductions are expected. For example, if the customer is only expected to respond during the hours of 8am to 6pm from Monday through Friday during non-holidays, then such historic hours should be used in the regression model.

The hourly CBL Adjustment is obtained by multiplying the WSA Factor by the temperature of the event hour minus the hourly average temperature of the CBL. The hourly average temperature of the CBL is the hourly average of the basis days used for the CBL.

Example 1:

Hourly average temperature of the CBL for hour ending 12 = 86°

Event temperature for Hour Ending 12 = 81°

WSA Factor = 688 kW/°F

CBL Adjustment for Hour Ending 12 = Temperature Delta * WSA Factor = (81° - 86°) * 688 kW/°F = -3440 kW

The CBL is adjusted down because the temperature of the event day is lower than the average hourly temperature of the CBL basis days.

A simple linear regression analysis fits a straight line through the set of points (load and temperature data) in such a way that makes the sum of squared residuals as small as possible. The first and last points of the estimated line are known as the Temperature Set Points. The Slope of the line between the two Temperature Set points is the WSA factor.



A piecewise linear regression analysis fits multiple contiguous straight lines through the set of data points (load and temperature data) in such a way that makes each of the sum of squared residuals as small as possible. The piecewise linear regression analysis results in multiple lines with multiple slopes that estimate the load and temperature relationship of the customer site data. The end points of each of the estimated lines are known as the Temperature Set Points. Determining the number Temperature Set Points can be accomplished by using a Piecewise Linear Regression Break Point algorithm or by data observation at points where the slope of the data appears to change significantly. Either methodology should result in minimizing the sum of squared residuals for each of the estimated lines.



The following table represents the weather station used for each Transmission Zone

Zone	Weather Station Short Name	Weather Station
AECO	ACY	Atlantic City International
AEP	CMH	Port Columbus International
APS	PIT	Pittsburgh International
BGE	BWI	Baltimore Washington International
COMED	ORD	Chicago O'Hare International
DAY	DAY	Cox-Dayton International
DOM	RIC	Richmond International
DPL	PHL	Philadelphia International
DUQ	PIT	Pittsburgh International
JCPL	EWR	Newark International
METED	PHL	Philadelphia International
PECO	PHL	Philadelphia International
PENELEC	JST	Johnstown Airport
PEPCO	DCA	Washington Reagan National
PPL	ABE	Allentown Lehigh Valley International
PSEG	EWR	Newark International
RECO	EWR	Newark International



- ~~— For those CSPs that wish to measure load reductions by comparing metered load against an estimate of what metered load would have been absent the reduction, a Customer Baseline Load (CBL) shall be calculated for each Demand Resource (“Load”).~~
- ~~— A Customer Baseline Load cannot be calculated for the Demand Resources participating as Emergency Load Response resources.~~
- ~~— A Customer Baseline Load is calculated for three timeframes: an Average Day CBL for Weekdays, the Average Day CBL for Saturdays, and the Average Day CBL for Sundays/Holidays. The standard CBL for all three timeframes is set forth in section 3.3A.2 (Customer Baseline Load) of the PJM Tariff.~~
- ~~— At the time it enters the Load Response Program, the Demand Resource or its representative (CSP), shall specify whether it desires to apply a Weather Sensitivity Adjustment (WSA) for the summer period (May-October, inclusive) or the winter period (November-April) or both.~~
- ~~— The election to apply the WSA may be changed only annually.~~
- ~~— The WSA shall increase or decrease the CBL. The WSA shall be calculated for interval-metered Demand Resources using a simplified methodology, including a regression analysis and analysis method, as defined in the Program Documentation. This simplified methodology only will be applicable for reductions in real-time Economic Load Response during the summer months when the hourly temperature at the nearest major airport equals or exceeds 85 degrees during each hour of the load reduction event and the WSA would make more than a five percent difference in the CBL that is calculated.~~
- ~~— The WSA, expressed in percentage terms, shall be applied to each hour of the CBL during the event period in order to establish a weather-adjusted CBL.~~
- ~~— The CSP may choose to apply to the Symmetric Additive Adjustment instead of the regression analysis or the simplified methodology described above. The election to apply the Symmetric Additive Adjustment shall be made at the time the Demand Resource is registered and annually thereafter. The Symmetric Additive Adjustment is defined in section 3.3A.3(a) (Weather Sensitive and Symmetric Additive Adjustment) of the PJM Tariff.~~
- ~~— For Demand Resources without interval data from the previous summer that select the regression analysis, the WSA shall initially be set at 100%. After one month of actual program response, a regression analysis shall be performed and the WSA shall be adjusted.~~
- ~~— In no event shall application of the WSA produce a weather-adjusted CBL that exceeds the Demand Resource’s historical, seasonal, on-peak non-coincident peak load.~~



- ~~— Case-by-case suggestions for alternative WSA methods or adjustments to the Demand Resource's historical, seasonal, on-peak non-coincident peak load may be approved by PJM if negotiated in good faith and agreed to by all appropriate parties.~~
- ~~— Curtailment Service Providers are responsible for forwarding the appropriate CBL data (to PJM within 60 days of the reduction).~~
- ~~— If the CBL data files are not received within 60 days, no payment for participation is provided.~~
- ~~— CBL data must be provided for each contiguous hour during which load reduction was accomplished.~~
- ~~— PJM will forward Customer Baseline (CBL) and Weather-Sensitive Adjustment (WSA) calculations to the appropriate EDC and LSE for optional review.~~
- ~~— EDC and LSE will provide feedback to PJM within ten (10) business days of receipt of data.~~
- ~~— Objection by the EDC or the LSE to the CBL, the Meter Data, or the retail rate shall be clearly set forth in the Comments related to the Settlement Data. The Curtailment Service Provider shall correct and re-submit the Settlement Data within 2 business days. The objecting EDC and/or LSE shall have 5 business days to review the re-submitted Settlement Data or PJM will assume acceptance. This procedure does not affect the requirement for the CSP to submit the settlement to PJM within 60 days of the load reduction event.~~
- ~~— The Demand Resource shall inform PJM directly or inform its CSP, who shall inform PJM, of any significant change to the Demand Resource's operations that increases or decreases the Demand Resource's CBL.~~
- ~~— A significant incremental change is defined as any operational or physical change to the Demand Resource's facilities that will adjust more than half the hours in the Demand Resource's CBL by at least 20% for more than twenty consecutive days. PJM may require and approve such adjustments to the CBL as are necessary to reflect the significant incremental change.~~
- ~~— All CBL data are subject to PJM Market Monitoring Unit audit.~~

10.4.3 Economic Energy Settlements Data Requirements

The CSP is responsible for providing all necessary information for each EDC account number unless otherwise approved by PJM for settlement and compliance calculations. CSPs are eligible to be paid



full LMP for the Registration's or dispatch group's reductions, provided that the LMP at the pricing point is at or above the Net Benefits Price and in accordance with Manual 28.

-All Registrations or dispatch groups must either clear in the Day-Ahead Market or be dispatch by PJM in order to be eligible for settlement revenue.

-All Registrations or dispatch groups are eligible for Make Whole payments subject to performance. Make Whole is hourly and based on lesser of bid volume and actual volume delivered:

- Make whole is only eligible for hour if load reductions is within +/- 20% of dispatch amount
- Make whole compensation is based on bid if bid => NBT
- Shutdown cost will not be paid if any hour in segment is outside 20% volume deviation
- Shutdown cost is paid once for all contiguous hours
- Segment make whole is sum of hourly make whole (ie: negative make whole will offset positive make whole)

All Registrations or dispatch groups are subject to Balancing Operating Reserve (BOR) charges for deviations greater than 20% from the PJM Day-Ahead or Real-Time Dispatch instructions.

DR resources may submit bids that are less than the Net Benefits price but will only be paid if appropriate LMP is greater than or equal to NBT.-

All settlements that are not submitted within 60 days of the economic event will settled by PJM with 0 kW hourly reductions. BOR will be assessed based on the deviations of the stand alone settlement or Dispatch Group settlement.-

All settlements that are still pending, denied or withdrawn after 75 days from the economic event will be settled by PJM- with 0 kW hourly reductions. BOR will be assessed based on the deviations of the registration settlement or Dispatch Group settlement, as appropriate.

Dispatch Group Settlements

To calculate the reductions achieved by the Dispatch Group after an economic event, individual settlements need to be created in eLRS.

- The CBL needs to be calculated in order to calculate the reductions for the individual registrations.

Formatted: PJM_Bulleted_Outline_1

Formatted: PJM_Normal

Formatted: PJM_Normal, No bullets or numbering



- The Dispatch Group economic event will be de-aggregated to the registration level settlements based on the registrations in the Dispatch Group early in morning the day after the operating day. The individual settlements are submitted by the CSP based on the normal registration level settlement process.
- The total reduction for the Dispatch Group is calculated once a day as the sum of all the reductions of the settlements. Once all of the settlements in the Dispatch Group reach their final state, the Dispatch Group load reduction is settled.
- The final state for a Dispatch Group economic settlement is achieved when all of the individual settlements within the Dispatch Group achieve the following status:
 - All settlements in Dispatch Group are confirmed.
 - Prior to the 60th day after the event, the CSP may mark the Dispatch Group ready for settlement. No further updates to any settlements may be done in the Dispatch Group.
 - On the 61st day after the event and all settlements are either confirmed, withdrawn or expired.
 - The 75th day after the event has been reached, the Dispatch Group settlement will be sent to settlements regardless of the individual status of any settlements in the group
- Dispatch Groups that are cleared or dispatched will be evaluated at the Dispatch Group level when evaluating BOR. Deviations and BOR will be assessed based on the reduction of the Dispatch Group.
- Market Settlements will provide settlement report based on Dispatch Group(s) and not by registrations.

10.4.3 Economic Energy Settlements Cost Allocation

The cost of Economic Demand Response settlements will be allocated to all of the Market participants with real-time exports from PJM and LSE's within a zone where zonal LMP is greater or equal to the appropriate Net Benefits Price and as described in Manual 28. Data required for emergency load response settlements:

- Real time LMP values by Zone or aggregate (including nodal) (PNODE)
- Actual Metered Reduction (Hourly MW) by Market Participant and by Zone or aggregate (including nodal) (PNODE)
- Actual Load (Hourly MW) by Market Participant and by Zone or aggregate (including nodal) (PNODE)

Formatted: PJM_Bulleted_Outline_1

Formatted: No bullets or numbering

Formatted: PJM_Normal

Formatted: PJM_Normal, No bullets or numbering



- Market Participant acting as CSP (ParticipantName)
- Data required for day-ahead economic load response settlements:
- Day-ahead LMP values by Zone or aggregate (including nodal) (PNODE)
- Day-ahead load response scheduled MW quantities by Market Participant and by Zone or aggregate (including nodal) (PNODE)
- Real-time LMP values by Zone or aggregate (including nodal) (PNODE)
- Actual Metered Reduction (Hourly MW) by Market Participant and by Zone (PNODE)
- Actual Load (Hourly MW) by Market Participant and by Zone (PNODE)
- Load-serving entity (LSEOrgId)
- Market Participant acting as CSP (ParticipantName)
- Loss Factor
- Retail Rate (G & T)

Data required for real-time economic load response settlements:

- Real-time LMP values by Zone or aggregate (including nodal) (PNODE)
- Actual Metered Reduction (Hourly MW) by Market Participant and by Zone or aggregate (including nodal) (PNODE)
- Actual Load (Hourly MW) by Market Participant and by Zone or aggregate (including nodal) (PNODE)
- CBL (Hourly MW)
- Load-serving entity (LSEOrgId)
- Market Participant acting as CSP (ParticipantName)
- Loss Factor
- Retail Rate (G & T)

Real-time Operating Reserve Charges (to be applied when the bid of the Demand Resource cleared in the Day-ahead Energy Market and the Demand Resource over or under performed in the real-time)

There are two Operating Reserve calculations, which require the following information:

- Day-ahead Operating Reserves
- ShutDown Costs submitted biannually

Formatted: PJM_Normal

Formatted: PJM_Normal, No bullets or numbering

Formatted: PJM_Normal

Formatted: PJM_Normal, No bullets or numbering

Formatted: PJM_Normal, Indent: Left: 0"

Formatted



- ~~○ Balancing Operating Reserves~~
- ~~○ ShutDown Costs submitted biannually~~

Formatted: PJM_Normal, No bullets or numbering

Formatted

Formatted: PJM_Normal

10.5 Aggregation for Economic and Emergency Load Response demand resources

The purpose for aggregation is to allow the participation of end-use customers in the energy market that can provide less than 100 kW of demand response when they currently have no alternative opportunity to participate on an individual basis or can provide less than 100 kw of demand response in the day-ahead scheduling reserve (DASR), synchronized reserve (SR) or regulation (REG) markets when they currently have no alternative opportunity to participate on an individual basis. An aggregation shall meet the following requirements:

If the aggregation will only provide energy to the market then only 1 end use customer within the aggregation shall have the ability to reduce more than 99kw of load unless the CSP, LSE and PJM approve. If the aggregation will provide an DASR or SR ancillary service to the market then only 1 end use customer within the aggregation shall have the ability to reduce more than 99kw of load unless the CSP, LSE and PJM approve. If the aggregation will provide Regulation Only through and Economic Regulation Only registration to the market then only 1 end use customer within the aggregation shall have the ability to reduce more than 99kw of load unless the CSP and PJM approve.

Formatted: PJM_Normal

All end-use customers in an aggregation, except for an Economic Regulation Only registration shall be served by the same electric distribution company and/or Load Serving Entity (LSE) and have the same energy pricing point, where the EDC is the LSE for all end-use customers in the aggregation. ~~All end use customers in an Economic Regulation Only registration shall be served by the same electric distribution company and located in the same transmission zone.~~ If the aggregation will provide synchronized reserves, all customers in the aggregation must also be part of the same synchronized reserve sub-zone.

All end-use customers in an aggregation that settle at Transmission Zone, existing load Aggregate, or node prices shall be located in the same Transmission Zone, existing load Aggregate, or at the same node except for an Economic Regulation Only registration.

Each end-use customer site must meet the requirements for market participation by a demand Resource except for the 100 kW minimum load reduction requirement for energy and ancillary services.

An end use customer's participation in the energy and ancillary service markets shall be administered either under one economic registration or if only providing Regulation service then



with and Economic Regulation Only registration and an Economic (Energy Only registration) as outlined in this manual.-

10.5.1 Calculations for the weighted average ~~retail rate and~~ line loss factor

~~When all end-use customers in a Registration are not subject to the same retail rate, the rate for the Registration shall be the registration load reduction weighted average of the retail rates for end-use customers in an aggregation.~~

Formatted: PJM_Normal

When all end-use customers in a Registration are not subject to the same line loss factor, the factor for the Registration shall be the registration load reduction weighted average of the factors for end-use customers in an aggregation.

PJM shall calculate the Ratio Share for each end-use customer as the percentage share of the summation of the individual anticipated load reduction capabilities (Total kW).

~~PJM shall calculate the Weighted Average G&T (WA G&T) by multiplying the Ratio Share times the G&T for each end-use customer and totalizing the results. The WA G&T shall represent the G&T of the Registration.~~

PJM shall calculate the Weighted Average line loss factor (WA LF) by multiplying the Ratio Share times the loss factor (LF) for each end-use customer and totalizing the results. The WA LF shall represent the loss factor of the Registration.

PJM shall provide the calculation of all load weighted values and their supporting data to the LSE and CSP at the time of registration.

~~An example calculation would be:~~

Customer	1	2	3	Total
kW	32.02	22.46	50.91	105.38
Ratio Share	30.38%	21.31%	48.31%	100.00%
G&T \$	0.0500	\$ 0.0660	\$ 0.0890	
LF	1.0680	1.0790	1.0900	
WA G&T \$	0.0152	\$ 0.0141	\$ 0.0430	\$ 0.0722
WA LF	0.32448	0.22995	0.52654	1.08097

10.5.2 Settlement for Aggregation

All end-use customers in the Registration are considered to have individually participated in each curtailment event if cleared in Day Ahead market as scheduled by the CSP or dispatched by PJM in



Real Time market for the Registration. All supporting details as outlined below will be available to the LSE after the settlement is submitted by the CSP.

- Registration Customer Baseline (CBL) based on the sum of the each end use customer's meter data where each end use customer is defined as a unique EDC account number.
- Meter data for each end use customer in the aggregation.
- Metered Load - Each individual end-use customer in the aggregation will have its own metered load and the summation of the individual metered loads will represent the Registration metered load.
- ~~— Weighted Average G&T - The load reduction weighted average G&T rate shall be the value calculated for registration.~~
- Weighted Average Loss Factor - The load reduction weighted average loss factor shall be the value calculated for registration.

10.6 Interval Meter Equipment and Load Data Requirements

~~(Section becomes effective on 10/1/09)~~

A CSP, LSE, EDC or agent designated by the CSP may fulfill the interval metering equipment and load data responsibilities that are required by PJM of the CSP for economic and emergency demand response resources including ancillary services. Interval metering equipment and load data used for retail electricity service shall be deemed to meet PJM requirements for energy settlement and capacity compliance.

The following documentation shall be provided by the CSP to PJM when non-retail electric service metering equipment and load data will be utilized for settlements or compliance. The CSP shall verify that all documentation is accurate and maintain compliance to PJM metering equipment and load data requirements.

- The date the metering equipment was installed, tested and ready to record, store and communicate interval load data for DSR activity
- The person that installed the metering equipment
- The make and model of the meter
- Metering equipment accuracy (meter, CT and PT)
- CT & PT type designation



- CT ratio
- All metering equipment shall, at a minimum, meet appropriate ANSI c12.1 and c57.13 standards to ensure the metering equipment is within the Tariff defined accuracy standards
- Metering equipment used for ancillary services shall meet additional requirements as defined in the PJM Tariff and/or Manuals.
- If equipment does not meet these standards, then on an exception basis, a field test may be conducted to validate the accuracy as long as the electricity service is less than 600 volts. PJM will review the field test results and associated metering equipment configuration to determine whether or not the use of metering equipment will be permitted.
- Metering equipment may include a pulse data recorder used in conjunction with a meter.

The CSP or designated agent shall maintain the relationship between the load data, metering equipment, EDC account number and other Customer Identifiers as defined. Further, the CSP or designated agent shall submit to PJM the quality assurance protocol used to ensure metering equipment accuracy over time. All interval load data, except where also used for retail electric service, shall at a minimum comply with the NAESB VEE (validate, edit & estimate) standards, where applicable, for retail electric service to ensure the quality of the information. If a pulse data recorder is utilized then time shall be managed on a daily basis or per communication whichever is least frequent. Time may be checked and reconciled through the network time protocol. Load data, including both pre and post VEE data shall be maintained for 36 months by CSP or designated agent. The CSP and/or designated agent will comply with request for metering equipment and load data audit as necessary that may include but not be limited to the following:

- Being available for on-site verification of metering equipment
- Providing load data history for Pre and Post VEE load data
- Providing work order, cut sheet or other documentation to validate the installation of the metering equipment
- Load data reconciliation where there are two metering systems present

A CSP or their designated agent that violate these standards will not be allowed to manage the installation/maintenance of metering equipment and associated load data for PJM settlements or compliance.

Non-retail electric service load data used for settlements or compliance will not be reconciled by PJM to the retail electric service load data unless, to troubleshoot an issue or as part of an audit.



If the CSP elects to utilize non-retail electric service load data for settlements then CSP will provide 90 consecutive days of load data on an annual basis near the effective date of the registration to PJM and PJM will make this load data available to the appropriate LSE. In addition, CSP or PJM shall provide load data to the EDC, as appropriate, for the peak load contribution add back process.

All metering equipment and load data shall comply with these standards by October 1, 2009.

10.7 Use of Sub-meter load data to support demand response regulation compliance

“Sub-meter” shall mean a metering point for electricity consumption that does not include all electricity consumption for the end-use customer as defined by the electric distribution company account number. PJM shall only accept sub-meter load data from end-use customers for measurement and verification of Regulation service as set forth in the Economic Load Response rules and PJM Manuals.

Formatted: PJM_Normal

“Location” as used in the Economic Load Response rules shall mean an end-use customer site as defined by the relevant electric distribution company account number.

— Curtailment Service Providers that have end-use customers that will participate in the Regulation market may be permitted to use Sub-metered load data instead of load data at the electric distribution company account number level for Regulation measurement and verification as set forth in the PJM Manuals and subject to the following:

Formatted: PJM_Normal, Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

1.

— Curtailment Service Providers, must clearly identify for the Office of the Interconnection all electrical devices that will provide Regulation and identify all other devices used for similar processes within the same Location that will not provide Regulation. The Location must contribute to management of frequency control on the PJM electric grid or PJM shall deny use of Sub-metered load data for the Location.

Formatted: PJM_Bulleted_Outline_1, Numbered + Level: 1 + Numbering Style: a, b, c, ... + Start at: 1 + Alignment: Left + Aligned at: 0.5" + Indent at: 0.75"

a.

Formatted: Font: Bold

i. The CSP will submit single line diagrams to PJM unless otherwise approved by PJM with sub metered device(s) clearly specified at the location. PJM will verify that all similar devices at the location are sub metered and if the similar devices are not sub metered, PJM will deny use of sub meter load data unless the CSP can demonstrate that the electricity usage of such similar devices not sub-metered will not offset change in electricity usages of the electrical device that will provide the regulation service.

Formatted: PJM_Bulleted_Outline_1, Indent: Left: 0.75", Hanging: 0.25", Numbered + Level: 1 + Numbering Style: i, ii, iii, ... + Start at: 1 + Alignment: Left + Aligned at: 0.75" + Indent at: 1.25"

Formatted: Font: Bold



b. If the registration to participate in the Regulation market contains an aggregation of Locations, the relevant Curtailment Service Provider will provide the Office of the Interconnection with load data for each Location's Sub-meter through an after-the-fact load data submission process **upon request by PJM.**

Formatted: PJM_Bulleted_Outline_1, Numbered + Level: 1 + Numbering Style: a, b, c, ... + Start at: 1 + Alignment: Left + Aligned at: 0.5" + Indent at: 0.75"

Formatted: Font: Bold

i. All telemetry load data to PJM will be based on device electricity consumption for each registration. The registration load data must include load data from all locations and from all devices approved at each location on the registration. For example, if the registration has 3 locations and each location has 1 pump that will regulate then the telemetry load data will include the aggregate load data for all 3 pumps.

Formatted: PJM_Bulleted_Outline_1, Indent: Left: 0.75", Hanging: 0.25", Numbered + Level: 1 + Numbering Style: i, ii, iii, ... + Start at: 1 + Alignment: Left + Aligned at: 0.75" + Indent at: 1.25"

ii. If the registration is an aggregation of locations, the CSP will provide PJM with load data for each location's sub-meter through an after the fact load data submission process as determined by PJM. This will allow PJM to confirm that the aggregate load data sent through telemetry consist of all locations on such registration.

The Office of the Interconnection may conduct random, unannounced audits of all Locations that are registered to participate in the Regulation market to ensure that devices that are registered by the Curtailment Service Providers as providing Regulation service are not otherwise being offset by a change in usage of other devices within the same Location.

Formatted: PJM_Normal, Indent: Left: 0.5"

Auditing will include a method of sampling location level load data without CSP's prior knowledge of sites sampled. CSP will provide location level load data (which represents load data for the EDC account number) to PJM upon request through after the fact meter data submission process as determined by PJM.

2. All CSP meter equipment will conform to meter data standards set forth in the PJM Tariff and the PJM Operating Agreement and as defined in Manual 11, section 10 and all CSP telemetry will comply with the standards set forth in the PJM Tariff, PJM Operating Agreement and PJM Manual 12, section 4.

Formatted: PJM_Normal, Numbered + Level: 1 + Numbering Style: 1, 2, 3, ... + Start at: 1 + Alignment: Left + Aligned at: 0.25" + Indent at: 0.5"

3. The Office of the Interconnection may suspend the Regulation market activity of Economic Load Response Participants, including Curtailment Service Providers, that do not comply with the Economic Load Response and Regulation market requirements as set forth in Schedule 1 and the PJM Manuals, and may refer the matter to the Independent Market Monitor and/or the Federal Energy Regulatory Commission Office of Enforcement.



Section 11: Overview of the Day-ahead Scheduling Reserve Market

Welcome to the Overview of the Day-ahead Scheduling Reserve Market section of the **PJM Manual for Energy & Ancillary Services Market Operations**. In this section you will find the following information:

- An overview description of the PJM Day-ahead Scheduling Reserve Market (see “Overview of PJM Day-ahead Scheduling Reserve Market”).
- A list of the PJM Day-ahead Scheduling Reserve Market Business Rules (see “PJM Day-ahead Scheduling Reserve Market Business Rules”).

11.1 Overview of Day-ahead Scheduling Reserve Market

The Day-ahead Scheduling Reserve Market is a construct for a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System. The Day-ahead Scheduling [30-Minute] Reserve Market is a offer-based market that will clear existing reserve requirements on a day-ahead, forward basis.

The Day-ahead Scheduling Reserve Market is designed to create an explicit value for an additional ancillary service in the PJM Markets, on a short-term basis. A Day-ahead Scheduling [30-Minute] Reserve market can provide a pricing method and price signals that can encourage generation and demand resources to provide Day-ahead Scheduling reserves and to encourage new resources to be deployed with the capability to provide such services.

The Day-ahead Scheduling Reserve Market is designed to interact with the current PJM Operating Reserve construct. While a clearing market for Day-ahead Scheduling [30-Minute] Reserves may reduce out-of-market payments to generators in the form of Operating Reserve credits, it will not eliminate them, and the remaining Operating Reserve costs will continue to be allocated.

11.2 PJM Day-ahead Reserve Market Business Rules

11.2.1 Day-ahead Scheduling Reserve Market Reserve Requirement

- Current reserve requirements are detailed in ***PJM Manual M-13, Section 2***, and vary according to the specific PJM region. The requirements for each region are combined to determine the overall requirement for the RTO, and the overall RTO requirement would form the basis for clearing the forward market.



- The Day-ahead Scheduling Reserve Requirement will adhere to the requirements for Day-ahead Scheduling [30-Minute] Reserve defined by Reliability First Corporation and all applicable reliability councils for areas within the PJM RTO.
- The PJM RTO Day-ahead Scheduling Reserve Requirement will be defined as the sum of the Day-ahead Scheduling Reserve requirements defined for all zones and areas within the PJM RTO, including any additional Day-ahead Scheduling reserves scheduled in response to an RTO-wide Hot or Cold Weather Alert or other reasons for conservative operations.
- Future reserve requirements may be defined locationally based on operation criteria as documented in the PJM Manuals.

11.2.2 Day-ahead Scheduling Reserve Market Eligibility

- Day-ahead Scheduling Reserve Resources are defined as resources that meet the following eligibility requirements to provide Day-ahead Scheduling Reserve:
- Day-ahead Scheduling Reserve Resources comprise of all those resources that can provide reserve capability that can be fully converted into energy within 30 minutes from the request of the PJM dispatcher at the time of the request and is provided by equipment which may not necessarily at the time of the request be electrically synchronized to the system.
- A Day-ahead Scheduling Reserve Resource may be:
 - Equipment not electrically synchronized to the system. The equipment that generally qualifies in this category is shutdown run-of-river, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels; or
 - Additional generating capacity that is synchronized to the grid and scheduled and can increase output in 30 minutes (including condensing mode and pumped hydro that is in pumping mode) to provide additional Day-ahead Scheduling Reserve;or
 - Load response resources must be registered in the Economic Load Response program, indicate that they can be dispatchable by PJM in real-time and be able to be reduced within 30 minutes.
- Load response resources that are considered “batch load” resources as defined in the section 1.3.1A.001 of the Operating Agreement, may participate in the Day-ahead Scheduling Reserve market under the same conditions as exist for Synchronized Reserve with respect to having already reduced prior to receiving a PJM dispatch

Formatted: PJM Bullet 2, No bullets or numbering

Formatted: PJM Bullet 2, No bullets or numbering



instruction to do so. Such resources must remain off line for the duration of the PJM dispatch request in order to receive the Day-ahead Scheduling Reserve market payment.

- Day-ahead Scheduling Reserve Market offers may be submitted only for those resources located electrically within the PJM RTO.
- Resources may participate and be compensated in both the Day-ahead Scheduling Reserve and Synchronized Reserve Markets. In addition, resources may participate and be compensated in both the Day-ahead Scheduling and Regulation Markets. However, since resources cannot participate in both the Synchronized Reserve and Regulation markets, no resources can participate in the Day-ahead Scheduling Reserve, Synchronized Reserve AND Regulation markets and be compensated for all three.
- The following additional Demand Resources requirements must also be met in order to participate in the Day-ahead Scheduling Reserve Market:
 - Demand resources' response controls must be approved by PJM prior to participation in the Supplement Reserve Market including ability to be dispatched by PJM's Unit Dispatch System.
 - Demand resources providing Day-ahead Scheduling Reserve are required to provide telemetry that is capable of providing metering information at no less than a one minute scan rate.
 - Metering information of demand resources is not required to be sent to PJM in real time. Daily uploads at the close of the next business day after the operating day if an event has occurred are sufficient, as the response evaluation is performed after the fact.
 - Demand resources may be aggregated and offered into the PJM Day-ahead Scheduling Reserve Market as one combined resource if the appropriate telemetry is provided for the aggregated resource.
 - Demand resource participation will be limited to 25% of the RTO Day-ahead Scheduling Reserve Requirement.
 - Demand Resources will be allowed to participate in the Day-ahead Scheduling Reserve Markets if approved by the appropriate Regional Reliability Council.

Formatted: PJM Bullet 2, No bullets or numbering

11.2.3 Day-ahead Scheduling Reserve Market Rules

- The following offer and operational information must be supplied through the eMKT System:



- Day-ahead Scheduling Reserve Availability.
- Day-ahead Scheduling Reserve Offer Price - Offers to provide Day-ahead Scheduling [30-Minute] Reserve are in dollars/MW of reserve to be provided, and \$0/MW is a valid offer.
- A valid generator or demand response energy offer must be available in the Day-ahead Energy Market to participate.
- Energy resources will need to have an energy offer available in the Day-ahead Market to participate in the Day-ahead Scheduling Reserve Market.
- All generator units that have submitted day-ahead energy offers and meet the Day-ahead Scheduling Reserve Market Eligibility requirements will be considered available to provide Day-ahead Scheduling reserve (Must offer requirement)..
- All demand resources that have submitted day-ahead energy offers and meet the Day-ahead Scheduling Reserve Market Eligibility requirements may provide Day-ahead Scheduling reserve (eMKT System default = unavailable). Demand resources may voluntarily make themselves available to provide Day-ahead Scheduling Reserve.
- Day-ahead Scheduling Reserve Offer Quantity (MW) for Online Units is derived as the lesser of:
 - difference of the Emergency Max – DA Dispatch Pt scheduled
 - Energy Ramp Rate * (30 minutes)
- Day-ahead Scheduling Reserve Offer Quantity (MW) for Offline Units is:
 - Emergency Max

Formatted: PJM Bullet 2, No bullets or numbering

Formatted: PJM Bullet 2, No bullets or numbering

Formatted: PJM Bullet 2, No bullets or numbering

11.2.4 Day-ahead Scheduling Reserve Market Offer Period

- Market participants wishing to offer into the Day-ahead Scheduling Reserve Market must supply offer and operational data on a day-ahead basis, with offers due to PJM by 1200 noon EPT on the day before the operating day (same timeline as Day-ahead Energy Market)..
- Day-ahead Scheduling Reserve offers are locked as of 1200 noon EPT the day prior to operation. All generating units listed as available for Day-ahead Scheduling Reserve with no offer price will have their offer prices set to zero.

11.2.5 Day-ahead Scheduling Reserve Market Clearing



- PJM would clear the forward market for Day-ahead Scheduling Reserves via a simultaneous optimization with the energy market as part of the Day-ahead Market mechanism.
- The Operating Reserve objective utilized in the Day-ahead Market and on which the Day-ahead Scheduling [30-Minute] Reserve market that would clear will be calculated based on the PJM load forecast for the upcoming operating day.
- The market clearing would result in an hourly price for Day-ahead Scheduling [30-Minute] Reserve for the next day, and would be posted along with the resource-specific Day-ahead Scheduling [30-Minute] Reserve awards by 1600 EPT via the PJM eMKT System.
- The hourly Day-ahead Scheduling Reserve clearing price is fixed once calculated and posted by 1600 EPT the day before the Operating Day.
- The hourly clearing price for Day-ahead Scheduling Reserve would be based upon the offer prices submitted by the selected resources, together with any opportunity cost a resource incurs in the day-ahead market as a result of being backed down in the day-ahead joint-optimization process in order to meet the RTO Day-ahead [30-minute] reserve requirement.
- The Day-ahead Scheduling Reserve Market clearing price is set equal to the merit order price of the highest cost Day-ahead Scheduling Reserve resource necessary to meet the remaining requirement.
- Resource merit order price (\$/MWh) = resource Day-ahead Scheduling Reserve offer + resource Day-ahead Scheduling Reserve opportunity costs.
- Both generator startup costs and demand resource shutdown costs are divided over the expected commitment period for the resource, as part of the market clearing process. Neither of these costs are including in the clearing price.
- Day-ahead Scheduling Reserve start-up costs are defined as applicable generator startup costs required to provide Day-ahead Scheduling Reserve or demand resource shutdown costs required to provide Day-ahead Scheduling Reserve.
- Day-ahead Scheduling Reserve opportunity costs are defined as applicable generator opportunity costs required to provide Day-ahead Scheduling Reserve or applicable demand resource opportunity costs required to provide Day-ahead Scheduling Reserve. Opportunity cost for Demand Resources is zero.
- The resource Day-ahead Scheduling Reserve offer is that which is submitted by the owner via the eMKT System by 1200 hours (noon) on the day preceding the operating day.



- The Day-ahead Energy Market LMP is used in the Day-ahead Scheduling Reserve opportunity cost calculations.

11.2.6 Day-ahead Scheduling Reserve Market Operations

- Those resources receiving a day-ahead award for Day-ahead Scheduling [30-Minute] Reserve would receive the hourly clearing price for the awarded MW amount as long as they were capable of providing the reserve in real time as outlined in the Day-ahead Scheduling Reserve Performance section below.

11.2.7 Day-ahead Scheduling Reserve Performance

- Resources that receive a Day-ahead Scheduling [30-minute] Reserve award are not required to maintain the awarded amount of reserve capability in real-time operations.
- Measurement of the performance of assigned resources will be as follows:
 - For resources with a start time plus notification time of greater than 30 minutes, the resource is required to be on line and operating at PJM's direction during the hour of the award with a real-time dispatchable range (Real-time Emergency Maximum – Real Time Economic Minimum) at least as great as day-ahead dispatchable range (Day-ahead Emergency Maximum – Day-ahead Economic Minimum).
 - For resources with a start time plus notification time of less than or equal to 30 minutes, the resource would be required to be available to the PJM operator for dispatch during the hours of the award and start within 30 minutes if dispatched by PJM.
 - If a unit with a Day-ahead Scheduling Reserve award for any hour in the day is requested to start in an hour that it did not receive a Day-ahead Scheduling Reserve award, the unit must start within 30 minutes in order to receive the award for the day.
 - Hydro resources are required to be available to the PJM operator for dispatch during the hours of the award.
- For Demand Resources, measurement is the difference between the demand resource's MW consumption at the time a resource is requested by PJM dispatch to reduce and its MW consumption after 30 minutes of the request. In order to allow for small fluctuations and possible telemetry delays, demand resources consumption at the start of the event is defined as the greatest telemetered consumption between one (1) minute prior to and one (1) minute following the issuance of the dispatch instruction. Similarly, a demand resource's consumption thirty minutes after the dispatcher request is defined as the

Formatted: PJM Bullet 2, No bullets or numbering



lowest consumption measured between twenty nine (29) and thirty (31) minutes after the start of the request.

11.2.8 Day-ahead Scheduling Reserve Market Obligation Fulfillment

- Each Load Serving Entity (LSE) on the PJM system incurs a Day-ahead Scheduling Reserve obligation in kWh based on their real-time load ratio share of the Day-ahead Scheduling Reserve assigned. Each LSE's obligation is equal to its load ratio share within its RTO times the amount of Day-ahead Scheduling Reserve assigned in the RTO. Any PJM market participant may incur or fulfill a Day-ahead Scheduling Reserve obligation through the execution of a bilateral Day-ahead Scheduling Reserve transaction as described below.
- Participants may fulfill their Day-ahead Scheduling Reserve obligations by:
 - Owning Day-ahead Scheduling Reserve resources from which the RTO obtains Day-ahead Scheduling Reserve ;
 - Entering bilateral arrangements with other market participants; or
 - Purchasing Day-ahead Scheduling Reserve from the Day-ahead Scheduling Reserve market.

Formatted: PJM Bullet 2, No bullets or numbering

11.2.9 Day-ahead Scheduling Reserve Bilateral Transactions

- Bilateral Day-ahead Scheduling Reserve bilateral transactions may be reported to PJM. Such reported bilateral Day-ahead Scheduling Reserve transactions must be for the physical transfer of Day-ahead Scheduling Reserve and must be reported by the buyer and subsequently confirmed by the seller through the eMKT System no later than 1600 the day after the transaction starts. Bilateral transactions that have been reported and confirmed may not be changed; they must be deleted and re-reported. Deletion of a reported bilateral transaction is interpreted as a change in the end time of the transaction to the current hour, unless the transaction has not yet started.
- Bilateral Day-ahead Scheduling Reserve transactions reported to PJM may be entered in MW of the purchaser's obligation. The minimum MW value is .1 MW
- Payments and related charges associated with the bilateral Day-ahead Schedule Reserve transactions reported to PJM posts shall be arranged between the parties to the bilateral contract.
- A buyer under a bilateral Day-ahead Scheduling Reserve preliminary billing data transaction reported to PJM agrees that it guarantees and indemnifies PJM, PJMSettlement, and other market participants for the costs of any purchases by the seller in the Day-ahead Scheduling Reserve Market, as determined by PJM, to supply



the reported bilateral transaction and for which payment is not made to PJMSettlement by the seller.

- Upon any default in obligations to PJM or PJMSettlement by a market participant, PJM shall not accept any new bilateral reporting by the Market Participant and shall terminate all of the Market Participant's reporting of eMarkets schedules associated with its bilateral Day-ahead Scheduling Reserve transactions previously reported to PJM for all days where delivery had not yet occurred.
- PJM posts Day-ahead Scheduling Reserve preliminary billing data on which market participants can use as a resource for pricing bilateral Day-ahead Scheduling Reserve transactions. The information can be found on the PJM Website at <http://www.pjm.com/markets-and-operations/market-settlements/preliminary-billing-reports/dsr-pjm.aspx>.

Formatted: Tab stops: Not at 0"

11.2.10 Day-ahead Scheduling Reserve Market Settlement

- Please refer to PJM Manual 28: Operating Agreement Accounting, Section 19: Day Ahead Scheduling Reserve Accounting for settlement details.
- Day-ahead Scheduling Reserve settlement is a zero-sum calculation based on the Day-ahead Scheduling Reserve provided to the market by generation and demand resource owners and purchased from the market by participants.



Attachment A: Interchange Energy Schedule Curtailment Order

Curtailment of Transmission or Recall of Energy:

The following is the curtailment order used by PJM for curtailing due to system constraints, Maximum Emergency and other PJM Emergencies. This curtailment order is used for transmission as well as capacity related curtailments.

PJM Dispatch may deviate from this pattern as necessary to maintain reliability. The *(italicized)* text below represents likely system events, as they would occur during a transmission constraint.

(Constrained System)

Non-Firm over Secondary Points not willing to pay congestion charges

Firm transmission used for a path other than the OASIS POR/POD. (NERC Transmission Bucket 1) Curtail by energy timestamp (LIFO).

Non-Firm not willing to pay congestion charges (NF-NPC)

Curtail descending by transmission time block (hour - NERC Transmission Bucket 2, day – NERC Transmission Bucket 3, week – NERC Transmission Bucket 4, and then month – NERC Transmission Bucket 5)

- Within a time block, curtail on/off-peak before curtailing all day reservations.
- Within the above categories curtail lower priced transmission first.
- Within the above categories curtail by transmission timestamp (LIFO).

Network Import not willing to pay congestion charges (Net-NPC)

(NERC Transmission Bucket 6) Curtail by energy timestamp (LIFO).

(Redispatch System)

Spot Market Import (SPTIN)

(NERC Transmission Bucket 6) Unload based on dispatch rate (non-zero rate schedules)

(Zero Dispatch Rate if applicable)

Unload spot market imports with zero dispatch rates



(Declare Emergency if applicable)

Must-take spot market import schedules are to be curtailed after non-firm not willing to pay congestion (npc) but before non-firm willing to pay congestion (wpc).

Non-Firm over Secondary Points willing to pay congestion charges

Firm transmission used for a path other than the OASIS POR/POD. (NERC Transmission Bucket 1) Curtail by energy timestamp (LIFO).

Non-Firm willing to pay congestion charges (NF-WPC)

Curtail descending by transmission time block (hour – NERC Transmission Bucket 2, day – NERC Transmission Bucket 3, week – NERC Transmission Bucket 4, and then month – NERC Transmission Bucket 5).

- Within a time block, curtail on/off-peak before curtailing all day reservations.
- Within the above categories curtail lower priced transmission first.
- Within the above categories curtail by transmission timestamp (LIFO).

Network Import willing to pay congestion charges (Net-WPC)

(NERC Transmission Bucket 6) Curtail by energy timestamp (LIFO).

Firm

Curtail schedules that effectively relieve the constraint, proportionally among Native Load customers, Network customers and customers taking Firm Point-to-Point transmission service. (NERC Transmission Bucket 7)

Example of Recall of Energy

An example of curtailment of capacity is curtailment of interchange energy schedules due to a maximum generation emergency. After schedules using non-firm energy (which effectively relieves the constraint) are curtailed in the order specified above, schedules using firm transmission would be curtailed. Note: the transmission is not curtailed; the energy is curtailed.

Based on the PJM Transmission Tariff, PJM formed the following wording, which describes the method for curtailing energy using a firm transmission reservation.



Firm

Curtail schedules that effectively relieve the constraint, proportionally among Native Load customers, Network customers and customers taking Firm Point-to-Point transmission service. (NERC Transmission Bucket 7)

Exports would be curtailed for maximum generation emergency; Native Load, Network Customers, and other imports would not be curtailed (imports are helpful during times of capacity shortage). This guideline is used for curtailment (on a whole contract basis) of energy schedules using firm transmission.

The method used to determine which firm schedules to curtail and in what order is explained below:

First, all effective cuts of schedules using lower priority transmission reservations (non-firm) are curtailed. Then recallable energy using firm transmission service is curtailed. The energy schedules using firm transmission service are cut on a whole contract basis and approximately proportionately among the transmission customers. The method used is to subdivide the schedule into two approximately equal segments, with about half of the any given companies energy in each block. These blocks are then subdivided repeatedly until each block is less than or equal to 400 MW. The blocks are then cut from first to last, as needed to follow load. If a block is to be subdivided and there are multiple customers, each with only one schedule in that block, the last customers to submit their energy schedules will be curtailed first. Similarly, a transmission customer's schedules will be curtailed in descending timestamp order.

Curtailment of Capacity Backed Resources

Capacity Backed Exports are those transactions sourced from generators or portions of generators on the PJM system that are not designated as PJM installed capacity.

At Maximum Emergency, PJM will not recall any energy from a resource that is not included in PJM Installed Capacity. If a resource has been de-rated from summer peak capacity, any export that exceeds the pro-rated capacity not attributed to PJM will be reduced to that pro-rated level.

Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. A 20 MW export is scheduled from PJM. There is no outage on the unit. The full 20 MW export will be scheduled.

Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. If there is a 40 MW partial outage of the unit, 3/4 (or 60/80) of the remaining capacity is considered installed. 1/4, or 20/80, of the remaining capacity is available as non-installed capacity and will not be curtailed during a PJM Maximum Emergency. In this example 30 MW remains as PJM installed capacity and 10 MW remains available for capacity backed exports. If the owner of Unit A scheduled a 20 MW export, 10 MW could be recalled during PJM Maximum Emergency.



At the conclusion of Maximum Emergency or at the conclusion of the outage, the export would be restored to the full 20 MW.

Attachment B: Pumped Storage Modeling

This Attachment describes a pumped storage prototype developed for PJM that could be used by participants to schedule their pumped storage plants in an optimal way.

Description of Model

This implementation models the pumped storage plant as a Mwh reservoir. The plant may have both generating units, that remove Mwh from the plant, and pumping unit that add Mwh to the plant. A pumping efficiency factor is used to translate the pump load to energy transferred into the plant. The following figure illustrates the model for a single time period.

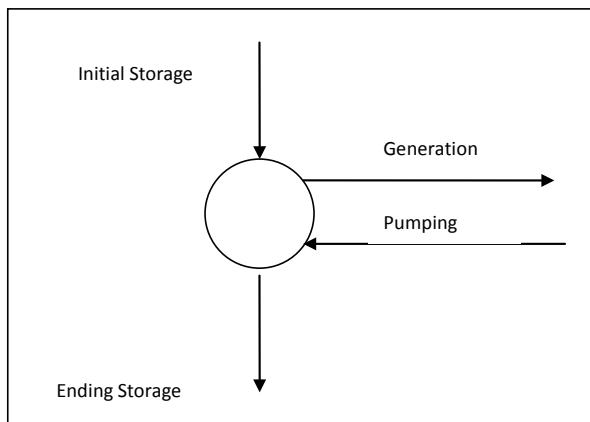


Figure 1 – Arc/Node Representation for a

This model enforces the classical “Conservation of Flow” constraint for each hour.

Hourly PlantStorage may also be constrained by MaxStorage and MinStorage values.

The Beginning and Ending storage for the day can then be constrained by setting MaxStorage and MinStorage values.

Since the objective of the unit commitment software is to minimize total cost over the study period, the resulting generation and pumping schedule will be maximized so as to produce the lowest possible system cost (maximum benefit). The conservation of flow constraint assures us that Pumping will only



occur if the cost of pumping can be offset by an associated benefit of generating when system prices are high.

In summary, the inputs to the model include:

Plant Data

- PumpedStorage– indicates this is a pumped storage plant and conservation of flow will be enforced
- Initial Storage
- Final Storage
- MaxStorage
- MinStorage
- Pumping efficiency factor.

Unit Data

- Min/Max generating and pumping limits

Note that pumping increases the storage by $- \text{PumpingEfficiency} * \text{PlantMwh}$, and generation decrease the storage by PlantMwh



Attachment C: PJM Procedure for Cost Reimbursement

This procedure addresses participant concerns regarding limited fuel situations and cost reimbursement. The aim of the procedure is to enable units that are requested to remain online by PJM System Operations past their initial, day-ahead commitment and in order to do so are forced to procure fuel at a higher cost than that on which their day-ahead or the Reliability Assessment (Rebid Period) offer was based, to better manage the risk associated with the additional costs associated with that operation. This procedure is not intended to guarantee cost recovery nor is it intended to address lost opportunity, profit maximization, or normal Operating Reserves make-whole payments where no change in fuel cost was experienced.

Offers

The mechanism in eMarket allows each generation owner to offer up to five cost schedules and one price schedule. In order to be eligible for reimbursement for higher cost fuel as a result of complying with a PJM dispatch request, participants will be required to enter a range of estimated costs to operate utilizing the higher priced fuel into one or more additional cost schedules (#1-89) and make this information available prior to the Day Ahead Market or the Reliability Assessment (if the unit was not taken in the DAM) on the Schedule Selection page of the Market User Interface (MUI). The range of estimated costs should cover the range of costs that participants believe they could face during the PJM operating day. In every case, the submitted costs must follow the current Cost Development Guidelines. Participants will be required to provide documentation directly to the PJM MMU of the basis for the estimated fuel cost(s) and associated operating cost(s). Participants will also be required to provide documentation during the PJM operating day of the actual fuel costs incurred and the actual associated operating cost(s). If MMU review shows that the new schedule regularly exceeds the actual costs incurred during the extended operating hours, the participant will be notified that the method for estimate calculations needs to be modified to more accurately reflect actual costs. If MMU review shows that the new schedule continues to exceed actual costs, the participant will not be permitted to utilize this procedure for making intra-day cost based offers.

Operations

If a unit has been asked to extend its hours of operation in real time and the unit has a limited fuel supply and must utilize higher priced fuel to remain online, the participant must inform the PJM system operator of the fuel cost change by requesting the real time offer to be switched to one of the additional available schedules. The participant must verify that the new schedule is the one reflecting fuel costs closest to those that will be actually paid to operate for the extended hours requested. The PJM



operator will evaluate whether the higher cost schedule is economic and if so, will log the unit on the new schedule in the Dispatch Management Tool.

Settlements

Participants who have been asked by PJM to extend a unit's run time and in order to comply with that request procured higher cost fuel have until 12:00 noon on the following business day to submit an e-mail to market_bids@pjm.com with the following information:

- Unit Name
- Date of operation
- Time of extended operation
- Number of new schedule
- Name of new Schedule
- Contact information (name of sender, phone, e-mail)
- Date and time of PJM Dispatch contact to generator
- Actual marginal cost of unit considering the actual cost of the fuel procured to continue operating

Market operations personnel will confirm with System Operations the operation of the unit. The information will be forwarded to the Market Settlement Operations department for compensation. In the event that this occurrence cannot be confirmed, the unit will be paid on the original schedule logged by the system operators.



Revision History

Revisions 50 (04/03/2012):

- Add bullet to Section 2.3.3 pointing to Manual M-28 regarding make whole provisions for generators committed in the Day-ahead Market and not run in real-time.

Republished 04/12/2012 to remove an erroneous bullet point that had stated: "A Generator that has been notified of a restriction due to a projected reliability condition, should not submit an economic maximum or maximum emergency bid into the Day-Ahead market higher than the communicated restriction. A forced outage ticket should be entered into eDART (Outside Management Control) for the duration of the restriction."

Revisions 49 (01/01/2012):

- Revisions made to reflect integration of the DEOK zone into the PJM footprint.

Revisions 48 (10/20/2011):

- Revision made to change the Synchronized Reserve Market interface from APSOUTH to the most limiting monitored transfer interface
- Revision made to the Synchronized Reserve maximum such that it can be less than or equal to the economic maximum for qualified resources that are granted exception due to a physical limitation
- Revision made to include Tier2 Synchronized Reserve floor offer of 0.1 MW in section 4.2.1

Revisions 47 (10/20/2011):

- Updated Section 3.2.1 to state that both Generation and Demand Resources must be able to provide 0.1 MW of Regulation Capability in order to participate in the Regulation Market.

Revisions 46 (06/01/2011):

Revisions made to reflect integration of the ATSI zone into the PJM footprint.

Revisions 45 (06/23/2010):

Revisions approved by stakeholders at MRC on June 23, 2010 to incorporate changes due to PJM markets manuals review.

Revisions made to clarify that PJM will be the counterparty to all transactions, unless market participants expressly and mutually contract between themselves (or self schedule to themselves).



Revisions have been approved at the Markets and Reliability Committee on April 21, 2010 and by FERC (Order ER10-1003 issued on May 5, 2010) (Reference: [FERC Order ER10-1003](#))

Revisions 44 (01/01/2010):

Revisions approved by stakeholders at MRC on November 11, 2009 to incorporate the following revision:

- One CSP rule (Section 10)

Revisions 43 (9/24/2009):

- Revised Section 2: Overview of Two-Settlement System section to reflect revisions to rules for submitting PLS, as approved by, as approved by the Markets & Reliability Committee on September 23, 2009

Revisions 42 (07/31/2009)

- Revised Section 2: Overview of Settlement System section to reflect Balancing Operating Reserve construct change as approved by FERC (ER08-1569).
- Revised Section 2: Overview of Settlement System to incorporate revisions to allow generators with negative offers to set price in the Day-ahead Market during a Minimum Generation event, as approved by the Markets & Reliability Committee on July 30, 2009
- Revised Section 10: Overview of Demand Response Participation to incorporate enhancement to DSR economic aggregation rules for resources providing Ancillary Services, as approved by the Markets & Reliability Committee on July 30, 2009

Revisions 41 (06/18/2009)

- Revisions to Section 3 to incorporate rules as approved by FERC on March 29, 2009 (Docket No. ER09-789) to allow for the recovery of lost opportunity costs incurred by generating market buyers and market sellers during the hour preceding the initial regulating hour and the hour following the final regulation hour.
- Cleanup revision on page 121.

Revision 40 (03/18/2009):



Revision to Section 10 to change the current rule requiring a participating end-use customer site have only one Curtailment Service Provider. Revision approved by Markets Reliability Committee on April 23, 2009.

Revision 39 (03/18/2009):

Revisions to Section 10 for Interval Meter Equipment and Load Data Requirements for DSR resources, Revisions approved by the Markets and Reliability Committee on March 18, 2009. Interval Meter Equipment and Load Data Requirements become effective on **October 1, 2009**.

Revision 38 (01/15/2009):

Revised Section 3 to incorporate rules to implement the Three Pivotal Supplier Test in the Regulation Market as approved by FERC (ER09-013) on November 26, 2008.

Revisions to Section 10 to incorporate Customer Usage Information Form

Revision 37 (11/24/2008)

Revised Synchronized Reserve Market rules to allow recalculation of Tier 1 Synchronized Reserve estimates 60 minutes prior to the market hour [as approved by MRC on June, 2008]

Revision 36 (08/06/2008)

Revised offer capping rules to eliminate exemptions per FERC Order EL08-34 (Effective May 16, 2008). Revisions made to Section 2.

Revised terminology for revised RFC Definition for Bulk Electric System (BES). Revisions made to Sections 1, 11 & 9.

Created new Section 11: Overview of Day-ahead Scheduling Reserve Market to incorporate markets rules approved per FERC Order ER08-780 (Effective May 30, 2008). Additional revisions made to Sections 1, 2, 5 & 6 for consistency.

Revised the Regulation Market Requirement to calculate on and off peak values. Revisions made to Sections 3 & 6.

Revision 35 (06/13/2008)

Section 10: Demand Resources Participation



Revised Demand Response Participation Rules effective June 13, 2008 for calculation of Customer Baseline (CBL) and associated rules per FERC Order ER08-824.

Revision 34 (2/29/2008)

Corrected typographical error made in Revision 33 on page 23.

Revision 33 (02/21/2008)

Section 2 – Revisions to reflect changes to the business rules for ‘up-to-congestion’ transactions.

Revision 32 (09/28/2007)

Section 2 – Revisions to reflect changes to the Day-ahead modeling of external bilateral transactions to put the generator or load (for import or export respectively) at the interface point.

Revision 31 (06/01/2007)

- Revisions for the implementation of Marginal Losses
- Revisions for the implementation of the Reliability Pricing Model

Revision 30 (03/20/2007)

- Section 2: Clarifying changes for consistency
- Section 3: Clarifying changes to reflect the implementation of Mixed-Integer Programming (MIP) in SPREGO optimization. Clarifying changes to reflect posting of Regulation Market Results.
- Section 4: Clarifying changes to reflect the implementation of Mixed-Integer Programming (MIP) in SPREGO optimization. Clarifying changes to reflect posting of Synchronized Reserve Market Results.
- Section 4: Revised rules to reflect the requirements of Demand Resources that are considered “batch load”
- Section 4: Revised rules to reflect Synchronized Reserve Market Consolidation for Reliability First Corporation.
- Section 5: Clarifying changes for terminology
- Section 6: Clarifying changes for consistency and terminology
- Section 6: Clarifying changes to reflect the scheduling process for External Market Sellers (XIC Units)
- Revision History permanently moved to the end of the manual.



Revision 29 (08/11/2006)

Exhibit 1: Updated to include the new Manual 30: Alternative Collateral Program.

Section 2: Revised rules to clarify the determination of a resource's hourly Desired MWh value and no-load compensation values.

Section 7: Timing requirement updates made regarding ramp reservations that are not scheduled against and ramp reservations that are placed In-Queue.

Added new section (Section 10) for Demand Response Participation

Revision 28 (06/13/06)

Revised Ancillary Services Rules for DSR.

Revised Ancillary Services Rules for RFC.

Revised for Three Pivotal Supplier rules.

Revision 27 (05/12/06)

- Section 7: Overview of External Transaction Scheduling
- Removed exception for spot import service.
 - Revisions were made to the following pages: 101 and 106.

Revision 26 (11/09/05)

- Section 7: Overview of External Transaction Scheduling
- Revised wording in paragraph 1 to reflect PJM's compliance with NERC Standard INT-001.

Revision 25 (08/19/05)

- Section 3: Overview of PJM Regulation Market
- Revised PJM Regulation Market Business Rules to create a single regulation market for the PJM RTO effective August 1, 2005.

Revision 24 (05/09/05)

- Section 3: Overview of PJM Regulation Market
- Revised PJM Regulation Market Business Rules to identify Ancillary Services Market Areas for Market Integration.



- Revised PJM Spinning Reserve Market Business Rules to define Southern Spinning Reserve Requirement.
 - Section 4: Overview of the PJM Spinning Reserve Market
- Revised PJM Spinning Reserve Market Business Rules to identify Ancillary Services Market Areas for Market Integration.
- Revised PJM Spinning Reserve Market Business Rules to define Southern Spinning Reserve Requirement.
 - Section 7: External Transaction Scheduling
- Revised expiration times for reservations that are not scheduled against that are made to start the following day.

Revision 23 (12/7/04)

- Section 2: Overview of PJM Settlement System
- Changed PJM Settlement Business Rules for to allow Unit Modeling Changes quarterly.

Revision 22 (10/01/04)

- Section 2: Overview of PJM Settlement System
- Changed PJM Settlement Business Rules for Virtual Bidding at External Interfaces
- Added PJM Settlement Business Rules for modeling multiple units for operating reserve calculations.
 - Section 3: Overview of PJM Regulation Market
- Changed PJM Regulation Market Business Rules to identify Ancillary Services Market Areas
- Added/Changed PJM Regulation Market Business Rules for Market Integration
- Changed PJM Regulation Market Business Rules to define Main/ECAR regulation requirement
- Changed PJM Regulation Market Business Rules to define new information supplied through the Settlement Market User Interface
 - Section 4: Overview of the PJM Spinning Reserve Market
- Changed PJM Spinning Reserve Market Business Rules to identify Ancillary Services Market Areas
- Added/Changed PJM Spinning Reserve Market Business Rules for Market Integration



Revision 21 (01/31/04)

- Created a new section (Section 7: External Energy Scheduling)
- Revised Exhibit 1: List of PJM Manuals to reflect additional manuals which have been created in 2003.

Revision 20 (09/01/03)

- Section 1: Overview of Scheduling Operation
- Revised exhibit 2.
 - Section 2: Overview of PJM Settlement System
- Revised exhibit 2.
 - Section 3: Overview of PJM Regulation Market
- Changed High Regulation Limit to Regulation Max
- Changed Low Regulation Limit to Regulation Min
 - Section 4: Overview of the PJM Spinning Reserve Market
- Changed PJM Spinning Reserve Market Business Rules to define new information supplied through the Settlement Market User Interface: Condense Startup Cost, Condense Hourly Cost, Condense Notification Time, and Spin as Condenser.
- Added Spinning Reserve Market Business Rule regarding Balancing Operating Reserves for units that are pool-assigned Tier 2 spinning reserve.
 - Section 5: Scheduling Philosophy and Tools
- Revised exhibit 4.
- Added exhibit 5.
- Revised exhibit 12.
- Revised exhibit 13.
- Removed all Attachments
 - Attachment A: Markets Database Dictionary has been removed
 - The Markets Database Dictionary provides PJM market participants with definitions for each of the data elements in the Markets Database. The Markets Database is an Oracle database that replaced the PJM unit commitment database. It is the repository of all generation offers, demand bid data and schedules for the Day-ahead Energy



Market, Real-time Energy Market, Regulation Market, and Spinning Reserve Market. The Markets Database Dictionary can be found on the PJM Web site at <http://www.pjm.com/etools/downloads/emkt/market-database-data-dictionary.pdf>.

- Attachment B (Offer Forms) has been deleted since the forms are no longer used
- Attachment C (eMKT User's Guide) has been removed
- The PJM eMKT Users Guide provides market participants with the information needed to participate in the PJM settlement, regulation markets and spinning reserve markets. The user guide describes the settlement software, the spinning reserve and regulation software, and the tasks that market participants can perform, as well as the expected system responses. The eMKT Users Guide can be found on the PJM Web site at <http://www.pjm.com/documents/downloads/user-guides/ts-userguide.pdf>
- Attachment D (Source & Sink List) has been removed
- Instructions on how to download the valid sources and sinks for the Day-ahead Energy Market can be found in the PJM eMKT Users Guide. The eMKT Users Guide can be found on the PJM Web site at <http://www.pjm.com/documents/downloads/user-guides/ts-userguide.pdf>
- Participants can also download the PJM Network Model information from the PJM Web site at www.pjm.com/markets/energy-market/bus-price-model.html.
- Attachment E: Interchange Energy Schedule Curtailment Order
- This attachment has been renamed "Attachment A."
- Attachment F: External Interface Specification Guide has been removed
- The External Interface Specification Guide is intended to help market participants in the PJM settlement, regulation and spinning reserve markets who want to develop their own interfaces for exchanging market data with PJM instead of using the default Market User Interface provided in PJM. The External Interface Specification Guide can be found on the PJM Web site at <http://www.pjm.com/services/training/downloads/externalspecs1.pdf>.

Revision 19 (12/01/02)

- Revised Attachment E: Interchange Energy Schedule Curtailment Order.

Revision 18 (12/01/02)

- Revised Attachment E: Interchange Energy Schedule Curtailment Order.

Revision 17 (12/01/02)

- Added new Section 4: Overview of the PJM Spinning Reserve Market.



- All remaining sections re-numbered respectively.

Revision 16 (05/18/01)

- Revised Section 2: Overview of the PJM Settlement System. Updated 'Market Sellers' subsection to include rules involving the designation of Maximum Emergency and Maximum Economic generation, numbered items 22 and 23, respectively.

Revision 15 (02/01/01)

- Revised Section 5: Scheduling Strategy & Method. Under subsection 'External Transactions', updated 60/45/30 minute rule to the new 60/30/20 minute rule. Also added bullet: "Hourly transactions will only be accepted after 1600 EPT (1400 EPT on non-business days) of the day before the Operating Day. Lastly, listed under 'Validating and Confirming Transaction Requests', a bullet was added to read:
 - "Ensure a valid NERC Tag has been associated. A valid NERC Tag is one in which:"
 - The profile is entirely covered by the tag
 - The tag duration is not longer than the schedule
 - The tag does not overlap profiles within a schedule
 - The tag is not used for multiple schedules
- Removed Attachment A: Definitions and Abbreviations, and all references. Attachment A is being developed into a new PJM Manual for ***Definitions and Abbreviations (M-35)***. All remaining attachments have been renumbered and all references have been corrected.

Revision 14 (08/24/00)

- Revised Section 5: Scheduling Strategy & Method. In subsection "*Processing Market Information*", added text pertaining to Deviations from Day-ahead Market for Pool Scheduled Resources, and Credits for Cancellation of Pool Scheduled Resources.

Revision 13 (08/15/00)

- Revised Section 5: Scheduling Strategy & Method. Added text pertaining to Ramp Violations.

Revision 12 (07/25/00)

- Revised Section 5: Scheduling Strategy & Method.

Revision 11 (06/16/00)



- Attachment F: Interchange Energy Schedule Curtailment Order
- Revised Curtailment of Capacity Backed Resources.
- Capacity Backed Exports are those transactions sourced from generators or portions of generators on the PJM system that are not designated as PJM installed capacity.
- At Maximum Emergency, PJM will not recall any energy from a resource that is not included in PJM Installed Capacity. If a resource has been de-rated from summer peak capacity, any export that exceeds the pro-rated capacity not attributed to PJM will be reduced to that pro-rated level.
- Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. A 20 MW export is scheduled from PJM. There is no outage on the unit. The full 20 MW export will be scheduled.
- Example: Unit A has a summer rated capacity of 80 MW, where 60 MW is designated as installed capacity and 20 MW is not. If there is a 40 MW partial outage of the unit, 3/4 (or 60/80) of the remaining capacity is considered installed. 1/4, or 20/80, of the remaining capacity is available as non-installed capacity and will not be curtailed during a PJM Maximum Emergency. In this example 30 MW remains as PJM installed capacity and 10 MW remains available for capacity backed exports. If the owner of Unit A scheduled a 20 MW export, 10 MW could be recalled during PJM Maximum Emergency. At the conclusion of Maximum Emergency or at the conclusion of the outage, the export would be restored to the full 20 MW.

Revision 10 (06/01/00)

- Attachment F: Interchange Energy Schedule Curtailment Order
- Removed Non-Firm over Secondary Points schedules requested after 2:00 p.m. of the day before operations and Non-Firm schedules requested after 2:00 p.m. of the day before operations from curtailment order.
- Added category: Curtailment of Capacity Backed Resources.

Revision 09 (06/01/00)

- Revised to reflect the Multi-Settlement Process implementation.

Revision 08 (04/01/00)

- Attachment B: Unit Commitment Database



- Removed reference to Maximum Scheduled Generation in section Unit Commitment – Scheduling Data (Cost Capped) for Steam Unit and Schedule Data #7 Schedule Operating Data.
- Removed reference to Maximum Scheduled Generation in section Unit Commitment – Scheduling Data (Cost Capped) CT Unit and Schedule Data #5 Unit & Schedule Operating Data.
- Removed reference to Maximum Scheduled Generation in section Unit Commitment – Scheduling Data (Cost Capped) Diesel Unit Data #5 Schedule Operating Data.

Revision 07 (06/01/99)

- Section 3: Scheduling Strategy & Method
- Revised to reflect the new addition of Attachment F (see below).
- Added 'new' Attachment F: Interchange Energy Schedule Curtailment Order.

Revision 06 (10/06/98)

- Section 3: Scheduling Strategy & Method
- Guidelines and requirements for the submission of Offer Data, and confirmation and PJM acceptance of schedules/transactions under "Spot Market Energy" and "Bilateral Transactions" of "Processing Market Information" were revised.

Revision 05 (04/01/98)

- Attachment C: Offer Forms
- Added "Exhibit C.7: Market Seller Aggregate Bid for Non-Designated Resource (E-Schedules Contracts)"
- Attachment E: Source & Sink List
- Added Attachment E: Source & Sink List
- Section 1: Overview of Scheduling Operations
- Revised exhibits and text.
- Section 2: Scheduling Philosophy & Tools
- Revised exhibits and text.
- Section 3: Scheduling Strategy & Method



- Added exhibits and text describing Locational Marginal Pricing application to the Scheduling process.
- Section 4: Posting OASIS Information
- Revised exhibits and text.
- Section 5: Hourly Scheduling
- Revised exhibits and text.

Revision 04 (01/30/98)

- Section 3: Scheduling Strategy & Method
- Changed PJM contact phone numbers for receipt of Offer Data to include 610.666.4532
- under “Spot Market Energy.” Added
- “A schedule is not accepted without confirmation of the schedule details with all parties.
- External offers are subject to the 500 MW ramp rule. The ramp rules outlined under “Bilaterals” in this section apply to offers.”
- under “Spot Market Energy.” Added
- “Offers Submitted More Than One Day in Advance

Offers may be submitted up to seven (7) days in advance (e.g., a bid for the tenth of the month could be submitted as early as the third of the month).

Offers submitted more than one day in advance received after 12:00 noon will not be processed until the following day.

Spot Market offers submitted more than one day in advance are not considered binding until 12:00 noon of the day before operations.

Ramp room will be held for the schedule, but neither PJM nor the market participant is bound to the schedule before 12:00 noon of the day before the operating day. Up to this time, either party may decline the offer without penalty.

A change to one day of a multi-day offer nullifies the timestamp for the rest the offer. The offer will be given a new timestamp and scheduled as though the rest of the schedule was submitted at the time of the change (including ramp room).



Transmission reservations that are not used due to cancelled spot market offers will be subject to transmission charges as appropriate.

PJM will notify the submitter of the acceptance status of offers submitted more than one day in advance by 4:00 p.m. of the day before operations or earlier as specified by the submitter. No offer will be marked as accepted before 12:00 noon of the business day before the operating day.

Offers may be withdrawn before PJM notifies the PJM Member of bid acceptance and before 4:00 p.m. of the business day before operations or 12:00 noon of the non-business day before operations.”

- under “Spot Market Energy.”
- Changed heading “Data Requirements” from “Aggregate Offer Data Requirements:” under “Spot Market Energy.”
- Changed
- “identity of all parties that are engaged in the schedule (e.g., buyers, sellers, marketers, transmitters, and brokers)”
 - from
- “identity of all parties that are engaged in the Bilateral Transactions (e.g., buyers, sellers, marketers, transmitters, and brokers)”
 - under “Data Requirements” in “Spot Market Energy.”
- Changed
 - “Offers may be withdrawn before PJM notifies the External PJM Member of bid acceptance and before 4:00 p.m. of the business day before operations or 12:00 noon of the non-business day before operations. All offers for the same period from the same Market Seller of a higher price than the withdrawn offer are also considered withdrawn.”
 - from
 - Offers may be withdrawn before PJM notifies the External PJM Member of bid acceptance and before 4:00 p.m. A withdraw of a bid after either of the aforementioned result in a non-delivery charge, unless withdrawing a resource specific offer due to a forced outage demonstrated to the satisfaction of the PJM. All offers for the same period from the same Market Seller of a higher price than the withdrawn offer are also considered withdrawn.
- under “Data Requirements” in “Spot Market Energy.”



- Changed
- “If the discrepancies are resolved without change to the original Bilateral Transaction request by 4:00 p.m., the schedule status is marked as confirmed. If discrepancies are resolved with changes to original Bilateral Transaction request before the scheduling deadline, the time stamp is updated to the time at which the discrepancies are resolved with the PJM.”
- from
 - “If the discrepancies are resolved without change to the original Bilateral Transaction request by 4:00 p.m., the schedule status is marked as confirmed. If discrepancies are resolved with changes to original Bilateral Transaction request before 2:00 p.m., the time stamp is updated to the time at which the discrepancies are resolved with the PJM.”
 - under “Confirmation of Bilateral Transactions” in “Bilateral Transactions.”
- Attachment C: Offer Forms
- Changed PJM contact phone numbers for receipt of Offer Data to include 610.666.4532.

Revision 03 (01/01/98)

- Section 3: Scheduling Strategy & Method
- Changed “The Regulation Requirement for the PJM Control Area is defined as follows:
 - PJM -specified percentage of the PJM Valley Load Forecast (currently 1.1%). This requirement is in effect during the Off-Peak Period (0000-0459 hours).
 - PJM -specified percentage of the PJM Peak Load Forecast (currently 1.1%). This requirement is in effect during the On-Peak Period (0500-2359 hours).”
- from “The Regulation Requirement for the PJM Control Area is defined as follows:
 - PJM -specified percentage of the PJM Valley Load Forecast (currently 1.1%). This requirement is in effect during the Off-Peak Period (2300-0659 hours).
 - PJM -specified percentage of the PJM Peak Load Forecast (currently 1.1%). This requirement is in effect during the On-Peak Period (0700-2259 hours).”
- Changed Exhibit 3.2: Regulation Requirement Timeline.
- Attachment D: Process Diagrams



- Added “Attachment D: Process Diagrams.”

Revision 02 (09/23/97)

- Changed selected references to PJM Member to market participant.
- Changed PJM phone number for receipt of Offer Data during business hours from “610-666-8947” to “610-666-4548.”
- Changed PJM phone number for checking Offer Data during non-business hours from “610-650-4307” to “610-666-4510.”
- Changed PJM phone number for receipt of Bilateral Transactions (North/West) during non-business hours from “610-666-8807 to “610-666-4510.”
- Section 1: Overview of Scheduling Operations
- Revised “(2) Unmetered Market Buyer - An Unmetered Market Buyer is a Market Buyer that is making purchases of energy from the PJM Interchange Energy Market for consumption by metered end-users or end-users that are located outside the PJM Control Area.” in “Market Buyers” under “PJM Member Responsibilities.”
- Revised “purchase transmission capacity reservation in order to receive generation from PJM Interchange Energy Market if the energy is being delivered to end-users that are located outside the PJM Control Area” in “Market Buyers” under “PJM Member Responsibilities.”
- Section 2: Scheduling Philosophy & Tools
- Deleted “verifies that transmission service exists” in “Transaction Management System” under “Scheduling Tools.”
- Revised “The deadline for both internal and external participants to submit information for the next day is 12:00 Noon of the previous PJM business day. After this deadline, no further offers are accepted for the next day and the UCDB is locked. The deadline is only extended when there is a computer problem at the PJM” in “Marginal Scheduler” under “Scheduling Tools.”
- Section 3: Scheduling Strategy & Method
- Revised “(4) PJM notifies via ALL-CALL, of the PJM Regulation Requirement” in “PJM Actions” under “PJM Regulation Requirements.”
- Revised “ (6) PJM notifies via ALL-CALL, in the event of a Regulation Requirement shortage” in “PJM Actions” under “PJM Regulation Requirements.”



- Revised “Each PJM Member, that has a requirement to serve load within the PJM Control Area, provides the PJM with a forecast of its requirements by 1200 hours on the day before the Operating Day. Regardless of how the PJM Member’s load is supplied, the PJM Member submits the following Operating Day forecast information to the PJM: in “PJM Member Load Forecasts” under “Processing Market Information.”
- Revised “Each PJM Member makes its own choice based on the information it possesses. Exhibit 3.5 illustrates the relationship between self- and PJM -scheduling for a particular resource” in “Self-Scheduled Resources” under “Processing Market Information.”
- Revised heading “Buy/Sell Request for External Energy” to “Spot Market Energy” under “Processing Market Information.”
- Revised “Spot Market requests are in the form of offers. There are general requirements for offer data, as well as specific requirements for internal and external participants” in “Spot Market Energy” under “Processing Market Information.”
- Replaced “Internal offers must be resource specific unless a schedule with an internal (metered) participant is agreed to beforehand. This is because PJM must account for every MW of energy within the PJM Control Area” with “A PJM Member must be in possession of the power to sell it as Spot Market energy (i.e., no entity can be in the contract path between the PJM Member selling the energy and PJM)” in “Spot Market Energy” under “Processing Market Information.”
- Added “PJM does not accept bids where the PJM Interchange Market is the source and sink (e.g., PJM-Market Participant-PJM)” in “Spot Market Energy” under “Processing Market Information.”
- Added “PJM does not accept bids for less than one continuous hour” in “Spot Market Energy” under “Processing Market Information.”
- Revised “PJM does not accept offers for resources committed to supply Operating Reserves to another Control Area. PJM will not double count units internal to PJM for Operating Reserves. If energy is being offered from a resource to PJM and is already included in the PJM Operating Reserve, the energy can be accepted but will not participate in PJM Operating Reserve accounting. Offers not properly submitted are rejected. The PJM Member is notified of the reason for rejection and the PJM Member may then take action to submit a new offer” in “Spot Market Energy” under “Processing Market Information.”
- Revised heading “Internal PJM Member Requirements” to “Resource Specific Offer Data Requirements” in “Spot Market Energy” under “Processing Market Information.”
- Deleted heading “External PJM Member Requirements” in “Spot Market Energy” under “Processing Market Information.”
- Deleted “External PJM Members submit offer data via both telephone and facsimile; numbers are listed under General Requirements. External PJM Members use the forms



found in Attachment C to submit offers” in “Spot Market Energy” under “Processing Market Information.”

- Deleted “External Market Buyers submit the following data, for the next operating day only:
- specific amount of energy for each hour of the day
- dispatch rate above which it does not desire to purchase OASIS number (the “transaction” number from the “Buy/Sell ATC” page of the PJM OASIS. More details on procedures for making a transmission service request via the PJM OASIS can be found on the PJM OASIS Users Guide @ <http://oasis.pjm.com>) for the transmission service reservation(s) which will be used to deliver the energy for the desired point of receipt of the intention to purchase transmission if the offer is accepted”
- in “Spot Market Energy” under “Processing Market Information.”
- Deleted “Valid offers are entered into the Transaction Maintenance System (TMS) for analysis by the Marginal Scheduler” in “Spot Market Energy” under “Processing Market Information.”
- Deleted “complete energy path” in “Spot Market Energy” under “Processing Market Information.”
- Added heading “Aggregate offer Data Requirements” and the following text in “Spot Market Energy” under “Processing Market Information:”
- “Aggregate offer data shall be submitted via both telephone and facsimile; phone numbers are listed under General Requirements. External PJM Members use the forms found in Attachment C of this manual to submit offers.
- A request to change offer data after an offer has been accepted (e.g., dispatch level, dispatch rate, path) will be rejected.
- PJM Members delivering Spot Market Energy to the PJM Interchange Energy Market submit the following data for the next operating day only:
- identity of all parties that are engaged in the Bilateral Transaction (e.g., buyers, sellers, marketers, transmitters, and brokers)
- minimum and maximum dispatch levels for each hour
- identity of any neighboring External Control Area identifiers and priorities, if applicable
- dispatch rate above which it does not desire to sell
- PJM Members requesting Spot Market Energy from the PJM Interchange Energy Market submit the following data for the next operating day only:



- identity of all parties that are engaged in the Bilateral Transaction (e.g., buyers, sellers, marketers, transmitters, and brokers)
- minimum and maximum dispatch levels for each hour
- dispatch rate above which it does not desire to purchase
- For Spot Market Energy to be delivered external to the PJM Control Area, OASIS number (the “transaction” number for the “Buy/Sell ATC” page of the PJM OASIS - More details on procedure for making a transmission service request via the PJM OASIS can be found on the PJM OASIS Users Guide @ <http://oasis.pjm.com>) for the transmission service reservation(s) which will be used to deliver the energy for the desired point of receipt or the intention to purchase transmission if the offer is accepted.
- identity of any neighboring External Control Area identifiers and priorities, if applicable”
- Deleted “External Market Sellers reports the following data for aggregate offers, the next operating day, up to the next business day only:
- complete energy pay
- dispatch rate below which it does not desire to sell
- hours of energy availability
- minimum and maximum dispatch levels”
- in “Spot Market Energy” under “Processing Market Information.”
- Deleted “This data constitutes a binding offer. Valid offers are entered into the Transaction Maintenance System (TMS) system for analysis by the Marginal Scheduler” in “Spot Market Energy” under “Processing Market Information.”
- Revised “Aggregate *Offer Data* - PJM compares the offer characteristics to the forecasted system conditions and Marginal Scheduler output. See “Forecasting PJM Generation Requirement” in Section 3 of this manual for more information” in “Spot Market Energy” under “Processing Market Information.”
- Revised “Resource Specific *Offer Data Evaluation* - Resource Specific Offer Data remains in Marginal Scheduler for evaluation. If the offer is not accepted before or during the operating day, the offer is considered rejected” in “Spot Market Energy” under “Processing Market Information.”
- Revised “If an offer is accepted or rejected, the PJM Member is notified via phone and fax. A confirmation fax is sent to the PJM Member (see Attachment C). For any accepted offer the PJM Member is notified by telephone by PJM as soon as possible. For External PJM



Members, the contact information requested on the fax form (Attachment C) must be listed on the offer facsimile” in “Spot Market Energy” under “Processing Market Information.”

- Added heading “Non-Delivery of Spot Market Energy” and the following text in “Spot Market Energy” under “Processing Market Information:”
- “A PJM External Market Seller will not be assessed a non-delivery charge if participants were not able to provide delivery for one or more of the following valid and documented reasons which physically prevented delivery and which was not reasonably anticipated at the time of scheduling:
 - transmission system constraints prevented delivery
 - generation outages of source generator(s) (resource must be specified in original Offer)
 - supplier or intervening power system emergencies prevent delivery
- A PJM External Market Buyer will not be assessed a non-delivery charge if the participant was prevented from delivery by one or more of the three conditions described above, the participant subsequently attempted to reschedule delivery, and PJM was unable to comply with the timing requirements for continuity of the transaction.
- Non-delivery charges described in Section 1.6.5 and 1.6.6 of Attachment K of the Tariff will continue to be assessed for all other non-delivery situations.
- The interface path of a Spot Market Energy schedule will not be changed on-shift (hourly).”
- Changed heading “Data Requirements Involving PJM Members External to PJM” to “Data Requirements Involving Parties External to PJM” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “If a transaction is reported after 2:00 p.m. of the business day before the operating day, the transaction uses non-firm transmission, congestion is expected on the system, and the transaction might contribute to the congestion, the request for the transaction will not be accepted. These schedules are submitted to the non-business hours facsimile or telephone number provided above.” in “Bilateral Transactions” under “Processing Market Information.”
- Added “valid NERC TIS Tag” in “Bilateral Transactions” under “Processing Market Information.”
- Deleted “identity of all PJM Members that are engaged in the Bilateral Transaction (e.g., buyers, sellers, marketers, transmitters, and brokers)” in “Bilateral Transactions” under “Processing Market Information.”
- Deleted “type of transaction (wheel in, wheel out, losses, firm, non-firm)” in “Bilateral Transactions” under “Processing Market Information.”



- Deleted “scheduled start/stop dates and time” in “Bilateral Transactions” under “Processing Market Information.”
- Deleted “quantity of service by hour (maximum and minimum MW) in increments of 1 MW/hour (1,000 kW/hour)” in “Bilateral Transactions” under “Processing Market Information.”
- Deleted “identity of any neighboring External Control Area identifiers and priorities” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “identity of associated transmission service reservation(s) for each hour of the Bilateral Transaction. This is the “transaction” number on the “Buy/Sell ATC” page of the PJM OASIS. Only one transmission service reservation may be applied to one energy schedule in any given hour. More details on procedures for making a transmission service request via the PJM OASIS can be found on the PJM OASIS Users Guide at <http://oasis.pjm.com>)” in “Bilateral Transactions” under “Processing Market Information.”
- Added “identity of any neighboring External Control Area identifiers and priorities” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “Bilateral Transactions scheduled for delivery to native load must be submitted by the Market Participant that reserved the Transmission Service or the LSE. The LSE ultimately receiving the energy and the Market Participant that reserved the Transmission Service must both confirm the Bilateral Transaction. All parties to the transaction must confirm the transaction” in “Bilateral Transactions” under “Processing Market Information.”
- Added “valid NERC TIS Tag is received (see www.nerc.com)” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “valid energy transaction type (firm, non-firm, wheel in, wheel out, loses)” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “if using non-firm transmission, then transaction must be reported to PJM before 2:00 p.m. of the business day before the operating day” in “Bilateral Transactions” under “Processing Market Information.”
- Added heading “Additional Validations for a Bilateral Transaction Schedule using On-Peak or Off-Peak Transmission Service Reservations” in “Bilateral Transactions” under “Processing Market Information.”
- Added Exhibits 3.10, 3.11, 3.12 and 3.13 in “Bilateral Transactions” under “Processing Market Information.”
- Added heading “Frequently Asked Questions (regarding on-peak and off-peak energy scheduling)” and the following text in “Bilateral Transactions” under “Processing Market Information.”



- “(Q1) A Market Participant has reserved off-peak daily transmission for Wednesday, but ramp room is not available at 0700 or 2300.
- (A1) Two possible solutions are 1) the energy may be scheduled from 0000 to 0800 or 2) the energy may be scheduled from 0000 to 0715 and from 2315 to 2400.
- (Q2) A Market Participant has reserved on-peak weekly transmission. Ramp room is available from 0700 to 2300 Tuesday through Friday, but ramp room is not available at 0700 or 2300 on Monday.
- (A2) The energy may be scheduled 0700 to 2300 Tuesday through Friday. One solution to the Monday ramp limit would be to schedule the energy from 0645 to 2245.”
- Deleted “Because Internal Bilateral Transactions do not cross a PJM interface, the 500 MW ramp rule does not apply to these transactions. Internal Bilateral Transactions are entered before the energy is scheduled to start. If a participant does not have direct access to TMS, the PJM Member can request PJM to confirm the transaction in TMS” in “Bilateral Transactions” under “Processing Market Information.”
- Revised “identity of all parties that are involved in the Bilateral Transaction (e.g., buyers, sellers, marketers, wheelers, and brokers)” in “Bilateral Transactions” under “Processing Market Information.”
- Section 4: Posting OASIS Information
- Replaced “Bilateral Transactions” with “transmission service reservations” under “PJM OASIS.”
- Revised “(1) Not later than 1600 hours of the day before each Operating Day, PJM posts the following information:” in “PJM Actions” under “PJM OASIS.”
- Attachment C: Offer Forms
- Revised PJM phone numbers on all forms.
- Added “For Internal Use” fields to Exhibits C.1, C.3 and C.4

Revision 01 (07/08/97)

- Section 2: Scheduling Philosophy & Tools
- Deleted “... (both those electing to curtail due to congestion and those electing to pay congestion charges) ...” under “Transaction Management System.”
- Section 5: Hourly Scheduling
- Deleted “... (not paying congestion charges) ...” under “Hourly Scheduling Adjustments.”



Revision 00 (05/01/97)

- Changed references to PJM Interconnection Association to PJM Interconnection, L.L.C.
- Changed references to PJM to PJM buses where appropriate.
- Changed references to PJM to PJM Control Area where appropriate.
- Changed references to PJM IA to PJM.
- Changed references to IA to PJM.
- Changed references to Mid-Atlantic Market to PJM Interchange Energy Market.
- Changed references to Mid-Atlantic Market Operations Agreement to Operating Agreement of PJM Interconnection, L.L.C.
- Changed references to pool to control area.
- Changed references to parties to PJM Members.
- Changed references to External Market Participant to Non-Metered PJM Member.
- Changed references to Internal Market Participant to Metered PJM Member.

Revision 00 (03/21/97)

- This revision is a draft of the PJM Manual for ***Scheduling Operations***.