

APPENDIX 1: ANCILLARY SERVICES

ISO New England Operating Procedure No. 8 Operating Reserve and Regulation

Effective Date: October 1, 2006

REFERENCES:

ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP4)

Northeast Power Coordinating Council Operating Reserve Criteria A-6

ISO New England Operating Procedure No. 14 -Technical Requirements for Generators, Demand Resources and Asset Related Demands

ISO New England Market Rules and Manuals

Table of Contents

I.	INTRODUCTION	3
II.	DEFINITIONS.....	3
III.	PROCEDURE.....	4
I.	REAL TIME OPERATING RESERVE REQUIREMENTS	5
A.	Ten-Minute Reserve Requirement.....	5
B.	TMOR Requirement	6
C.	Locational Reserve Requirements.....	6
II.	OPERATING RESERVE DISTRIBUTION	7
III.	OPERATING RESERVE RESTRICTIONS.....	7
IV.	SHORTAGE OF OPERATING RESERVE.....	7
V.	OPERATING RESERVE - CAPABILITY UNDER TEST CONDITIONS.....	8
VI.	REGULATION RESERVE REQUIREMENT	8
VII.	REAL-TIME REPLACEMENT RESERVE REQUIREMENT.....	8
VIII.	TESTING OF RESPONSE RATES	8
IX.	RESPONSIBILITY	9
	OP 8 Revision History	9

PART I - INTRODUCTION

Operating Reserve, in addition to the resources required to meet the actual New England Control Area load, is required to reliably operate the New England Control Area. Reserve Requirements, provide for:

1. Loss of generating equipment within the New England Control Area or within any other Northeast Power Coordinating Council (NPCC) Control Area.
2. Loss of transmission equipment within or between NPCC Control Areas that might result in a reduction of energy transfer capability within the New England Control Area or between the New England Control Area and any other Control Area.
3. Regulation in the New England Control Area.
4. Errors in forecasting New England Control Area loads.

This Procedure sets forth criteria for the establishment and administration of Operating Reserve and Regulation in the New England Control Area.

The objective is to ensure that the New England Control Area's bulk power supply system is operated at the prescribed level of reliability.

PART II - DEFINITIONS

Control Area -

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- (i) Match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from outside the electric power system(s) with the load within the electric power system(s);
- (ii) Maintain scheduled interchange with other Control Areas within the limits of Accepted Electric Industry Practice;
- (iii) Maintain the frequency of the electric power system(s) within reasonable limits in accordance with Accepted Electric Industry Practice and the criteria of the applicable regional reliability council or the NERC; and Provide sufficient generating capacity to maintain operating reserves in accordance with Accepted Electric Industry Practice. [Market Rule 1]

TEN-MINUTE RESERVE - The sum of TMSR and TMNSR that is fully available within ten minutes from the time first requested.

TEN-MINUTE NON-SPINNING RESERVE (TMNSR) -

TMNSR shall mean the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption. [Market Rule 1]

TEN-MINUTE SPINNING RESERVE (TMSR) -

TMSR shall mean the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System. [Market Rule 1]

THIRTY-MINUTE OPERATING RESERVE (TMOR) -

TMOR shall mean the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption. [Market Rule 1]

OPERATING RESERVE - Operating Reserve shall mean Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR). [Market Rule 1]

FIRST CONTINGENCY LOSS - The largest capability outage (MW) that would result from the loss of a single element.

SECOND CONTINGENCY LOSS - The largest capability outage (MW) that would result from the loss of a single element after allowing for the First Contingency Loss.

REGULATION - Regulation shall mean the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO Administrative Procedures. [Market Rule 1]

REPLACEMENT RESERVE – Replacement Reserve shall mean reserve other than TMSR, TMNSR or TMOR as defined in the ISO New England Manuals. [Market Rule 1]

REPORTABLE EVENTS - System disturbances involving losses of load, generation, or transmission facilities, which equal or exceed the following criteria, are reportable events:

- Actual net (interchange) tie line flow deviations equal to or greater than 500 MW
- Loss of generation or load equal to or greater than 500 MW
- System frequency deviations equal to or greater than 0.03 Hz

PART III - PROCEDURE

I. REAL TIME OPERATING RESERVE REQUIREMENTS

A. TEN-MINUTE RESERVE REQUIREMENT

During normal conditions, ISO New England shall maintain a quantity of Ten-Minute Reserve at least equal to the amount required to replace the First Contingency Loss in the New England Control Area. The energy associated with regulation reserves (Section VII) that is available within ten minutes may be utilized to satisfy Ten-Minute Reserve Requirements. Every available resource of generating capability, including regulation resources, Dispatchable Asset Related Demand, and capability made available by other qualifying load management techniques shall be considered for activation in an effort to maintain the required Ten-Minute Reserve at all times.

1. TMSR Requirement

One hundred percent (100%) of the New England Control Area's Ten-Minute Reserve Requirement shall be Synchronized Reserve except as described below.

To the extent that, in the judgment of the ISO New England Chief Operating Officer or an authorized designee, the New England Control Area's bulk power system can be operated within the North American Electric Reliability Council's (NERC), NPCC's, and ISO's established reliability criteria and without unduly imposing more severe operating conditions (emergency starts, short-time running, etc.) on Nonsynchronized Capability, the TMSR Requirement may be decreased to a minimum of twenty-five percent (25%) of the Ten-Minute Reserve Requirement based upon ISO New England's past performance in returning tie lines to pre-contingency values within fifteen minutes following loss of generation, in accordance with the following relationship:

The TMSR Requirement may decrease by ten percent (10%) of the Ten-Minute Reserve Requirement for every time ISO New England successfully returns its ACE to precontingency values, or to zero, following a reportable event where the resource loss is equal to or less than the magnitude of the first contingency loss. Successful recoveries that occur in the same month as a failure shall not be

counted that month towards a reduced TMSR Requirement. However, successful recoveries subsequent to a failure can be counted in the next month provided there are no failures in that month.

The TMSR Requirement shall increase by twenty percent (20%) for every time ISO New England fails to return its ACE to precontingency values or to zero within fifteen minutes following a reportable event where the resource loss is equal to or less than the magnitude of the first contingency loss. The maximum TMSR Requirement shall be one hundred percent (100%) of the New England Control Area's Ten-Minute Reserve Requirement.

Changes in the TMSR Requirement caused by ISO New England's performance in returning its ACE to precontingency values or to zero within fifteen minutes following a reportable event where the resource loss is equal to or less than the magnitude of the first contingency loss shall be calculated at the end of each month and shall be applied at the beginning of the next month. The ISO New England Chief Operating Officer or an authorized designee may increase the Ten-Minute Synchronized Reserve Requirement above the amounts specified by the above provisions. If warranted to ensure recovery from a contingency, and to comply with established criteria, the ISO will activate Operating Reserve based on economic priority to the extent possible, but should reliable operation of the power system require it, the ISO will activate Operating Reserve, as it deems necessary.

B. TMOR REQUIREMENT

In addition to the Ten-Minute Reserve Requirement, ISO New England shall maintain a quantity of TMOR at least equal to fifty percent (50%) of the Second Contingency Loss. Any excess Ten-Minute Reserve can be counted as Thirty-Minute Reserve.

During periods when system conditions threaten to reduce Ten-Minute Reserve below prescribed levels, TMOR may be redispatched to maintain Ten-Minute Reserve.

C. LOCATIONAL RESERVE REQUIREMENTS

Locational Reserve requirements are established for Reserve Zones and are further explained in Market Rule 1, Section III.9.2.3. The locational reserve requirements reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The locational reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

II. OPERATING RESERVE DISTRIBUTION

Operating Reserve shall be distributed to ensure that it can be fully utilized by ISO New England for any probable contingency without exceeding transmission system limitations and to ensure operation in accordance with NERC, NPCC, and ISO New England Manuals, operating policies and procedures.

III. OPERATING RESERVE RESTRICTIONS

ISO New England shall be responsible for designating the First Contingency Loss and the Second Contingency Loss in the New England Control Area. Frequent review of system configurations shall be made to ensure that all probable capability losses that could be caused by a First Contingency and resulting relay actions are considered.

When a generating unit is the largest First Contingency in the New England Control Area and, therefore, used to calculate the Ten-Minute Reserve Requirement, the capability of the unit, in excess of its output, cannot be considered as Operating Reserve. However, when a generating unit is the largest Second Contingency in the New England Control Area, the net capability of the unit, in excess of its output, may be considered as Operating Reserve.

When allocating Operating Reserve to the various resources throughout the New England Control Area, particular attention must be given to temporary limitations and deratings. Only that capability that can actually supply MW in the applicable period shall be classified as Operating Reserve.

Operating Reserve, if activated, shall be sustainable for at least one hour from the time of activation or the published NERC/NPCC criteria. It is recognized that units called upon to activate reserve will operate without relief until the ISO determines they are no longer needed.

IV. SHORTAGE OF OPERATING RESERVE

Normally, Operating Reserve will be provided to prescribed levels of Synchronized and Nonsynchronized reserve from within the New England Control Area. If available capability is insufficient to provide adequate Operating Reserve, ISO New England will implement the various Actions of OP 4 as appropriate to maintain Operating Reserve Requirements. During shortages of Operating Reserve, Thirty-Minute Reserve shall be re-dispatched to maintain Ten-Minute Reserve at the prescribed value.

If OP 4 Action 11 is implemented, and a shortage of Ten-Minute Reserve is forecast, ISO New England will recognize that voltage reduction load relief available in ten minutes provides Nonsynchronized Reserve. Ten-Minute Nonsynchronized Reserve will be synchronized to the system and brought to Ten-Minute Synchronized Reserve status whenever Ten-Minute Reserve falls below the full ten-minute requirement.

V. OPERATING RESERVE - CAPABILITY UNDER TEST CONDITIONS

Frequently, some capability is used to supply energy needs while it is in a test condition. This test energy normally is not released for ISO New England dispatch and must be added, megawatt-for-megawatt, to the Operating Reserve Requirement. However, based on the assumed degree of risk for the sudden loss of the total energy, ISO New England may recognize the test energy risk as being similar to other non-test capability and count the test energy as firm. In such cases, Operating Reserve Requirements need not be increased due to the test energy.

VI. REGULATION RESERVE REQUIREMENT

ISO New England shall maintain a portion of its Synchronized Capability on Regulation sufficient to satisfy the NERC Control Performance Criteria. The specific Regulation requirements are identified in ISO New England Manual for Market Operations (Manual M-11).

VII. REAL-TIME REPLACEMENT RESERVE REQUIREMENT

In addition to the Operating Reserve Requirements, ISO New England will maintain a quantity of Replacement Reserves in the form of additional TMOR for the purposes of meeting the NPCC requirement to restore its Ten-Minute Reserve within 105 minutes if it becomes deficient as a result of a contingency that is a reportable event and within 90 minutes if it becomes deficient and the deficiency is not a result of a contingency that is a reportable event, as described in NPCC Document C-09, Monitoring Procedures For Operating Reserve Criteria.

The ISO will not activate emergency procedures, such as ISO New England Operating Procedures No. 4 or 7, in order to maintain the Replacement Reserve Requirement.

To the extent that, in the judgement of the ISO New England Chief Operating Officer or an authorized designee, the New England Control Area can be operated within NERC, NPCC, and ISO New England established criteria, the Replacement Reserve Requirement may be decreased to zero based upon ISO New England's capability to restore Ten-Minute Reserve within NPCC requirements.

VIII. TESTING OF RESPONSE RATES

As outlined in ISO New England Manual for Market Operations (Manual M-11), ISO New England has the responsibility to conduct tests of response rates of both synchronized and non-synchronized resources.

The ability of resources to demonstrate Operating Reserve capability shall be tested at regular intervals. ISO New England will attempt to coordinate these tests with system conditions and Market Participants' normal testing practices.

IX. RESPONSIBILITY

ISO New England is responsible for operating the New England Control Area in accordance with established NERC, NPCC, and ISO criteria. This includes the responsibility for determining when Operating Reserve above minimum levels prescribed will be retained. Further, ISO New England is responsible for determining how best to meet Regulation and tie line response criteria.

ISO New England is also responsible for identifying the First Contingency Loss and the Second Contingency Loss; for determining the required amount of Operating Reserve; for specifying the type, location, and quantity to be maintained; for selecting the number of units as well as the location of units to be assigned to Regulation; for determining the required amount of Replacement Reserve and for communicating the directive to units for activating Operating Reserve in response to contingencies in the New England Control Area and/or NPCC.

LOCAL CONTROL CENTERS/MARKET PARTICIPANTS are responsible for communicating to ISO New England current system conditions affecting Operating Reserve. The Local Control Centers/Market Participants are also responsible for activating Operating Reserve for localized problems within a local area when time does not permit communication with ISO New England. When Operating Reserve is used by the Local Control Center(s), ISO New England is to be notified as soon as practicable and ISO New England will take action to restore Operating Reserve as soon as possible.

OP 8 REVISION HISTORY

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Ancillary Services Manual

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Table of Contents

1. Overview	1-1
1.1 Purpose	1-1
1.2 Summary of Services	1-1
1.3 Payments and Charges for Ancillary Services	1-2
1.4 Self-Supply of Ancillary Services	1-2
1.5 Metering Requirements	1-3
2. Scheduling, System Control & Dispatch Service	2-1
2.1 Description	2-1
2.2 Recovery of NYISO Costs	2-3
2.2.1 Costs Recovered Through NYISO Open Access Transmission Tariff	2-3
2.2.2 Costs Recovered Through NYISO Services Tariff	2-6
2.3 Payment for Service	2-6
2.3.1 Computation of Rate	2-6
2.3.2 Billing	2-7
2.3.3 Charges Associated with Local Reliability Rules	2-7
2.4 Services Performed at the Request of a Market Participant	2-7
3. Voltage Support Service	3-1
3.1 Description	3-1
3.2 Supplier Qualification	3-2
3.3 Responsibilities for Service	3-2
3.4 Payment for Service	3-3
3.4.1 Method for Determining the Payments for Voltage Support Service	3-3
3.4.2 Payments made to Suppliers for Voltage Support Service	3-3
3.4.3 Payments for Voltage Support Service Provided by Non-Utility Generators with Existing Power Purchase Agreements	3-3
3.4.4 Payments for Lost Opportunity Cost	3-4
3.4.5 Payments made by Transmission Customers and LSEs	3-5
3.5 Failure to Perform by Suppliers	3-5
3.5.1 Failure to Respond to NYISO's Request for Steady State Voltage Control	3-5
3.5.2 Failure to Provide Voltage Support Service when a Contingency Occurs on the NYS Power System	3-6
3.5.3 Failure to Maintain Automatic Voltage Regulator in Service	3-7
3.6 Reactive Power Capability Testing or Demonstration	3-7
3.6.1 Frequency, Timing, and Other Requirements	3-8
3.6.2 Test Procedure for Generators	3-8
3.6.3 Test Procedure for Synchronous Condensers	3-10
3.6.4 Reporting Requirements	3-10
3.6.5 Allowance for Out-of-period Reactive Capability Testing	3-11
3.7 Voltage Support	3-12
3.7.1 Request for Voltage Support Service	3-12
3.7.2 Voltage Support Availability	3-12
4. Regulation & Frequency Response Service	4-1

NYISO ANCILLARY SERVICES MANUAL

4.1	Description.....	4-1
4.2	Source of Service	4-1
4.3	Scheduling of Service.....	4-3
4.3.1	Generating Unit Operating States.....	4-3
4.3.2	Regulation Capacity Scheduling	4-4
4.3.3	Control Signals to Satellite Control Centers.....	4-5
4.3.4	Regulation Service	4-5
4.3.5	AGC & RTD Program Response.....	4-5
4.4	Performance Criterion.....	4-6
4.4.1	Performance Tracking	4-6
4.5	Regulation Service Settlements – Day-Ahead Market	4-7
4.5.1	Calculation of Day-Ahead Market Clearing Prices	4-7
4.5.2	Other Day-Ahead Payments.....	4-8
4.6	Regulation Service Settlements – Real-Time Markets	4-8
4.6.1	Calculation of Real-Time Market Clearing Prices	4-8
4.6.2	Calculation of Real-Time Market Clearing Prices for Regulation Service during EDRP/SCR Activations	4-9
4.6.3	Real-Time Regulation Service Balancing Payments	4-9
4.6.4	Other Real-Time Regulation Service Payments	4-9
4.7	Energy Settlement Rules for Generators Providing Regulation Service	4-10
4.7.1	Energy Settlements.....	4-10
4.7.2	Additional Payments/Charges When AGC Base Point Signals Exceed RTD Base Point Signals	4-10
4.7.3	Additional Charges/Payments When AGC Base Point Signals are Lower than RTD Base Point Signals.	4-11
4.8	Regulation Service Demand Curve.....	4-11
4.9	Reinstating Performance Charges.....	4-13
4.10	Temporary Suspension of Regulation Service Markets During Reserve Pick-Up	4-14
4.11	Charges Applicable to Suppliers That Are Not Providing Regulation Service.....	4-14
4.11.1	Persistent Under-generation Charges.....	4-14
4.11.2	Restoration of Performance Charges.....	4-14
4.11.3	Exemptions.....	4-15
4.12	Charges to Load Serving Entities	4-16
4.13	Regulation & Frequency Response Notification Procedures	4-16
5.	Energy Imbalance Service.....	5-1
5.1	Description.....	5-1
5.2	External Imbalances	5-1
5.3	Monthly Meter Reading Adjustments.....	5-2
5.3.1	Facilities Internal to the New York Control Area	5-2
5.3.2	Facilities on Boundaries with Neighboring Control Areas.....	5-2
5.3.3	Adjustment Verification.....	5-2
6.	Operating Reserve Service.....	6-1
6.1	Description.....	6-1
6.2	General Responsibilities and Requirements	6-2
6.2.1	NYISO Responsibilities	6-3
6.2.2	Supplier Eligibility Criteria	6-5

NYISO ANCILLARY SERVICES MANUAL

6.2.3	<i>Other Supplier Requirements</i>	6-6
6.3	<i>General Day-Ahead Market Rules</i>	6-6
6.3.1	<i>Bidding and Bid Selection</i>	6-6
6.3.2	<i>NYISO Notice Requirement</i>	6-7
6.3.3	<i>Responsibilities of Suppliers Scheduled to Provide Operating Reserves in the Day-Ahead Market</i>	6-7
6.4	<i>General Real-Time Market Rules</i>	6-8
6.4.1	<i>Bid Selection</i>	6-8
6.4.2	<i>NYISO Notice Requirements</i>	6-8
6.4.3	<i>Obligation to Make Resources Available to Provide Operating Reserves</i>	6-8
6.4.4	<i>Activation of Operating Reserves</i>	6-9
6.4.5	<i>Performance Tracking and Supplier Disqualifications</i>	6-9
6.5	<i>Operating Reserve Settlements – General Rules</i>	6-9
6.5.1	<i>Establishing Locational Reserve Prices</i>	6-9
6.5.2	<i>Settlements Involving Suppliers of Operating Reserves Located on Long Island</i>	6-9
6.5.3	<i>“Cascading” of Operating Reserves</i>	6-9
6.6	<i>Operating Reserve Settlements – Day-Ahead Market</i>	6-10
6.6.1	<i>Calculation of Day-Ahead Market Clearing Prices</i>	6-10
6.6.2	<i>Other Day-Ahead Payments</i>	6-12
6.7	<i>Operating Reserve Settlements – Real-Time Market</i>	6-12
6.7.1	<i>Calculation of Real-Time Market Clearing Prices</i>	6-12
6.7.2	<i>Calculation of Real-Time Market Clearing Prices for Operating Reserves During EDRP/SCR</i>	
Activations	6-14
6.7.3	<i>Operating Reserve Balancing Payments</i>	6-16
6.7.4	<i>Other Real-Time Payments</i>	6-16
6.8	<i>Operating Reserve Demand Curves</i>	6-17
6.9	<i>Self-Supply</i>	6-19
6.10	<i>Operating Reserve Charge</i>	6-19
6.11	<i>Failure to Provide Operating Reserve</i>	6-20
6.12	<i>Procedures for Notification of Poor Performers</i>	6-20
7.	Black Start Capability Service	7-1
7.1	<i>Description</i>	7-1
7.2	<i>Source & Scheduling of Service</i>	7-1
7.3	<i>Payment or Service</i>	7-2
7.4	<i>Black Start Service Procedures</i>	7-3
	Attachment A – VSS Qualification Request Form	A-1
	Attachment B – Generator MVar Capability Test	B-1
	Attachment C – Regulation Performance Adjustment	C-1
	Attachment D – Performance Standards	D-1

Table of Figures

Figure 3.1: Generator MVA _r versus MW Capability	3-1
Figure 3.4.4-1: Method for Calculating LOC	3-4
Figure 4.1: Generating Unit Operating Characteristics	4-2
Figure 4.3.1: Generating Unit Operating States.....	4-3
Figure 4.3: Perfect Performance	4-6
Figure 4.4: Error in Performance (30 Second bandwidth not included).....	4-7
Figure 6.1: Operating Reserve Requirements.....	6-2
Figure B-1: NYISO Voltage Support Ancillary Service Annual Reactive Capability Test Report	B-2
Figure B-2: Lagging Test Data Recording Form.....	B-3
Figure B-3: Leading Test Data Recording Form	B-4

Table of Tables

Table 1.1: Ancillary Services Summary	1-1
Table 1.2: Rate Schedules for Ancillary Services	1-2
Table 2.1: System Security Management in Real Time Functions.....	2-1
Table 2.2: Capacity Management Functions	2-2
Table 6.1: Ancillary Service Eligibility	6-3
Table 6.2: NYISO Locational Reserve Requirements	6-4

1. OVERVIEW

This section gives an overall description of the following Ancillary Services.

- Scheduling, System Control & Dispatch Service
- Voltage Support Service
- Regulation & Frequency Response Service
- Energy Imbalance Service
- Operating Reserve Service
- Black Start Capability Service

1.1 Purpose

The purpose of this Manual is to provide an overview of the Ancillary Services available in the New York market along with settlement process associated with each of the available ancillary services.

1.2 Summary of Services

Ancillary Services support the transmission of energy from resources to loads, while maintaining reliable operation of the New York State (NYS) Power System. Ancillary Services consist of physical equipment and human resources. The New York Independent System Operator (NYISO) is also responsible for directing the actions of Generation Resources and other facilities that provide Ancillary Services to the NYISO.

The NYISO coordinates the provision of all Ancillary Services and directly arranges for the supply of all Ancillary Services that are not self-supplied. Some Ancillary Services must be provided by the NYISO; others can either be provided by the NYISO or procured by the Transmission Customers and Suppliers themselves. Some Ancillary Services are provided at market-based prices, while others, due to the nature of the service, are provided at embedded cost-based prices. All Ancillary Service providers must be scheduled by the NYISO. [Table 1.1](#) presents a summary of the NYISO Ancillary Services.

Table 1.1: Ancillary Services Summary

Ancillary Service	Is the Service Location Dependent?	Who provides the Service – NYISO or Self-Supplied (SS)?	What is the Pricing method for the Ancillary Service?
Scheduling, System Control and Dispatch Service	No	NYISO	Embedded
Voltage Support Service	Yes	NYISO	Embedded
Regulation and Frequency Response Service	Yes	NYISO or (SS)	Market-based
Energy Imbalance Service	No	NYISO	Market-based
Operating Reserve Service	Yes	NYISO or (SS)	Market-based
Black Start Capability Service	Yes	NYISO	Embedded

1.3 Payments and Charges for Ancillary Services

Payments and charges for ancillary services are described in the [NYISO Accounting and Billing Manual](#) and set forth in the NYISO Open Access Transmission Tariff (OATT) and Services Tariff as noted in Table 1.2.

Table 1.2: Rate Schedules for Ancillary Services

Ancillary Service	OATT Rate Schedule	Services Tariff Rate Schedule
Scheduling, System Control and Dispatch Service	1	1
Voltage Support Service	2	2
Regulation and Frequency Response Service	3	3
Energy Imbalance Service	4	1
Operating Reserve Service	5	4 and 6
Black Start Capability Service	6	5

1.4 Self-Supply of Ancillary Services

Transmission Customers and Suppliers are permitted to Self-Supply certain Ancillary Services, as identified in [Table 1.1](#). In general, the following process must occur in order to Self-Supply Ancillary Services:

1. A Transmission Customer bids the resource required to provide the Ancillary Service into the Ancillary Services market.
2. The NYISO selects the successful bidders to provide each Ancillary Service. The selection of all Ancillary Service providers is subject to the same locational criteria.
3. Transmission Customers and Suppliers with resources selected by the NYISO use the revenues that they would otherwise have received for providing these services as an offset against charges they would otherwise need to pay the NYISO for the service.
 - The LSEs identify in their application to NYISO the Ancillary Services that they plan to purchase through the NYISO.
 - All suppliers of Ancillary Services using the self-supply option must place the facility under the operational control of the NYISO. All of these resources are subject to the same NYISO locational and performance criteria, and are subject to all payments and penalties as are defined for all other suppliers of the service.
 - For more information, see the [NYISO Accounting and Billing Manual](#).

1.5 Metering Requirements

- Ancillary Services Suppliers must ensure that adequate metering data is made available to the NYISO by direct transmission to the NYISO through existing Transmission Owner communication equipment.
- Additionally, for operational purposes, metered data provided to the NYISO must also simultaneously be provided to the Transmission Owner, which will handle such information consistent with the [OASIS](#) standards of conduct as specified in FERC Order No. 889.

4. REGULATION & FREQUENCY RESPONSE SERVICE

This section describes the regulation and frequency response service.

4.1 Description

Regulation and frequency response services are necessary for the continuous balancing of resources (generation and NY Control Area interchange) with load, and to assist in maintaining scheduled Interconnection frequency at 60 Hz. This service is accomplished by committing on-line generators whose output is raised or lowered (predominately using Automatic Generation Control (AGC)) as necessary to follow moment-by-moment changes in load. The service is in addition to operating reserve services required for system contingency purposes. The NYISO offers regulation and frequency response services to serve Load within the NY Control Area.

The NYISO establishes the regulation and frequency response requirements consistent with criteria established by North American Electric Reliability Council (NERC), which may vary by hour and by season. Seasonally, the NYISO shall post the hourly regulation and frequency response requirements and, prior to the start of the season, shall present the regulation and frequency response requirements to the System Operation Advisory Subcommittee (SOAS) for discussion and comment. Should the NYISO determine that it intends to establish regulation and frequency response requirements for any hour that are lower than any requirement for that hour in the seasonal regulation and frequency response requirements published as of March 1, 2004, it shall present, prior to posting, its analysis and the revised requirement to the Operating Committee for approval. Should the NYISO determine, for reliability reasons, that it intends to establish regulation and frequency response requirements for any hour that are higher than the requirement for that hour currently in effect, it shall raise the requirement, issue a notice as soon as possible, repost the hourly regulation and frequency response requirements for that season, and discuss its adjusted regulation and frequency response requirement for that hour at the next regularly scheduled Operating Committee meeting. Shortly after the end of each Capability Period, the NYISO shall present SOAS with an analysis of the regulation performance in that Capability Period. The NYISO also establishes generation resource performance measurement criteria and procedures for bidder qualification and for the disqualification of bidders that fail to meet such criteria.

4.2 Source of Service

Regulation service is bid into the market by individual units that have AGC capability and that wish to participate in the regulation market. Generating Resources are not obligated to participate and provide regulation service unless they have bid for Regulation and that bid has been accepted.

The NYISO selects regulation service in the Day-Ahead Market from qualified Generating Resources that bid to provide regulation service. Market Participants may submit bids to the NYISO for regulation services up to the Real-Time Market market-closed time (75-minutes

prior to the operation hour).

The bid evaluation program validates a regulation bid and returns a message to the bidder indicating that data supplied is either valid or is rejected. Rejected Bids (or any bid) may be changed and resubmitted prior to market closing time. Bid information includes:

- Regulation response rate, in MW/min
- Regulation availability/price, in \$/MW

The NYISO Market Participants User's Guide describes the bidding protocols and the checks that the NYISO makes to ensure validity. Regulation capacity (or regulating margin) is calculated as the regulation response rate times five minutes.

[Figure 4.1](#) shows how regulation capacity is defined with respect to a unit's operating range, for the situation without Reserve activation.

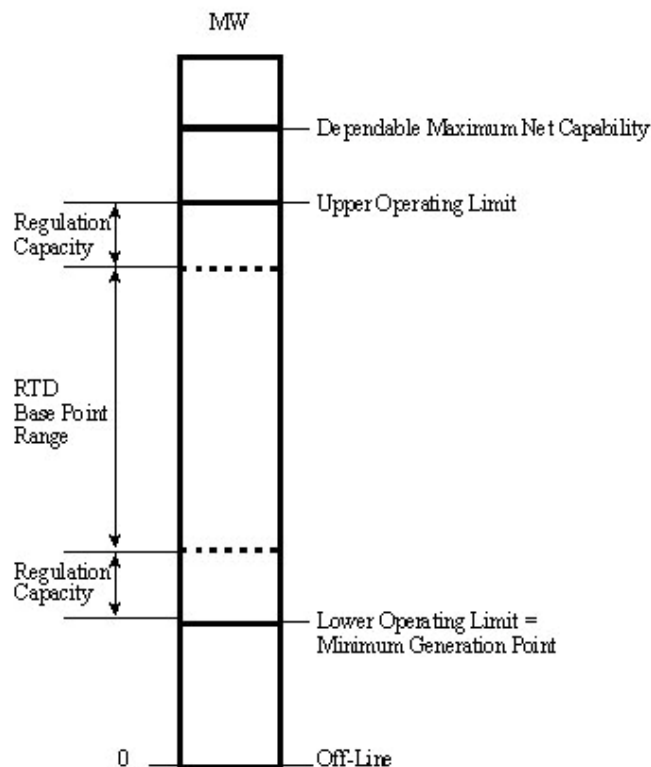


Figure 4.1: Generating Unit Operating Characteristics

There are up to five response rates that are bid by the suppliers:

- *Normal Response Rate (NRR)* — There may be up to three response rates given with each generator. They are used under non-reserve pickup conditions.
- *Regulation Response Rate (RRR)* — This response rate is given with the regulation bid and must be no less than 1 MW/minute.
- *Emergency Response Rate (ERR)* — This response rate is used under reserve pickup conditions. ERR must be greater than or equal to the capacity weighted average of the normal

response rates.

Individual units may bid into the market as groups of units, providing the units are pre-qualified to be bid and operated together as though they are a single unit for all generator bid services (units participating as part of a group are not allowed to bid individually or as part of another group). Pre-qualification specifications for units to bid as a group include metering support, billing, and performance measurements as if a single unit.

4.3 Scheduling of Service

Regulation requirements are determined by the NYISO consistent with industry standards set by NERC. The regulation requirements may include locational requirements and consider transmission constraints. Automatic Generation Control signals for regulation service are transmitted to the individual units via the Transmission Owners or directly from the NYISO, or both.

4.3.1 Generating Unit Operating States

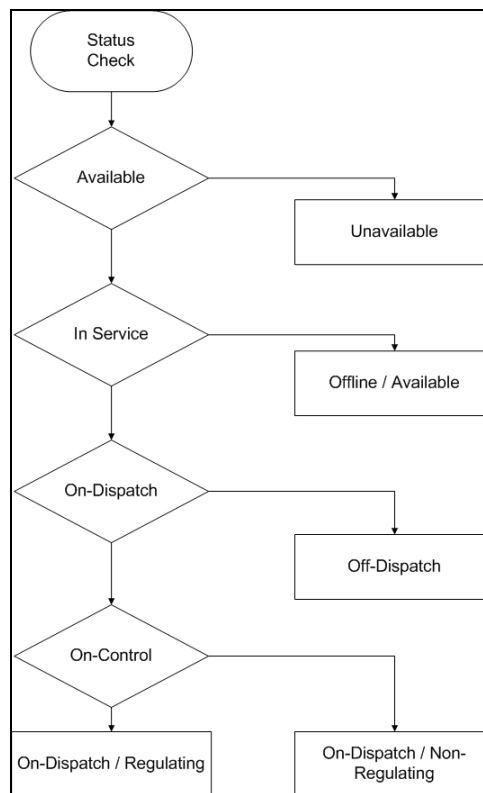


Figure 4.3.1: Generating Unit Operating States

Generating units have the NYISO operating states as shown in [Figure 4.3.1](#).

- **Unavailable** – The unit is Off-Line and is not available for any ancillary services contribution.
- **Off-Line/Available** – The unit is Out-of-Service and Off-Line, but is available for ancillary services contribution.
- **Fixed (Off-Dispatch)** – The unit is In-Service and On-Line and is not under automatic control. This unit's RT schedule is predetermined. Schedule changes may occur only on the quarter hour.
- **Flexible (On-Dispatch) and Non-Regulating** – The unit typically is not under automatic control. The basepoint for the unit is normally updated every five minutes. The unit does not participate in Regulation.
- **Flexible (On-Dispatch) and Regulating** – The unit is under automatic control. The unit has an Energy schedule that is established by RTD. The unit participates in Regulation as directed by AGC and, thus, may be requested to deviate from its RTD schedule.

4.3.2 Regulation Capacity Scheduling

Regulation capacity is allocated to each unit that was selected to supply regulation, according to the expected regulation response rate (RRR) times 5 minutes.

Regulation capacity is comprised of two regions. The upper region is bounded by the unit upper operating limit. The lower region is bounded by the minimum generation point. Each region is equal to the regulation capacity accepted for that Unit. (See [Figure 4.1](#), above)

Commitment for Additional Regulations

The NYISO may commit additional generation resources in the real-time market to provide regulation if any of the following conditions exist:

- 1) Insufficient regulation MW is bid into the Day-Ahead Market.
- 2) Units that were scheduled in the Day-Ahead Market to provide regulation services are not available in real-time.
- 3) More regulation services are required than had been anticipated would be needed in the Day-Ahead Market.

Replacement Regulation

Units, including those not awarded a forward contract to provide regulation in the First Settlement commitment process, may bid into the Second Settlement market for regulation. A generator providing replacement regulation in the real-time market will be paid based on:

- 1) The Real-Time market clearing price (MCP) for regulation

- 2) Its Scheduled regulation in MWs
- 3) The length of the period of time during which it provides regulation.

Regulation Default

A unit with a day-ahead regulation schedule that cannot provide regulation in real-time will receive a zero real-time regulation schedule and buy out of its day-ahead commitment. There are no other penalties for a “default.”

4.3.3 Control Signals to Satellite Control Centers

Control signals designating the value of Unit Desired Generation (UDG) for each unit are sent to the satellite control centers every six seconds.

4.3.4 Regulation Service

The AGC function calculates an area control error and allocates this error to selected regulating units in proportion to the amount of their scheduled regulations. AGC will determine the UDG for each unit by combining the unit’s regulation requirement (if any) with its ramped basepoint derived from its RTD 5-minute basepoint. The NYISO computer system will send UDGs to TOs that will in turn retransmit the UDGs to generating units in their control area. Regulation penalties for all NYCA units will be assigned by the NYISO directly to individual generating units based on their monitored performance.

The amount of regulation capacity (MW) and response rate (MW/Minute) that is required for the NY Control Area is established by the NYISO and can vary on a seasonal and hourly basis. The [*NYISO Transmission & Dispatching Operations Manual*](#) describes how the regulation requirements are defined for the New York Control Area.

4.3.5 AGC & RTD Program Response

The AGC program uses each supplier’s Regulation Response Rate in determining base points. The RTD program uses the Normal Response Rate. RTD-CAM may use either the Normal or the Emergency Response Rate, depending on reserve activation. All flexible suppliers, including those with and without a real-time reserve schedule, may be required to respond to a reserve Pick Up. Units with a real-time reserve schedule will have base points calculated using their Emergency Response Rates, others will have base points calculated using their Normal Response Rates.

In extreme cases when Area Control Error (ACE) exceeds the total available response from regulation suppliers with a Real-Time regulation schedule, the remaining ACE is distributed proportionally over the regulating resources without a Real-Time regulation schedule up to their capability to respond at their Regulation Response Rates. If this condition persists, the NYISO Shift Supervisor may run RTD-CAM to eliminate the imbalance. Alternatively, when more regulation services are required, the NYISO may request more regulation capacity from the Real-Time

regulation market.

A minimum ACE distribution value is established by the NYISO so that base point changes are distributed to only a few (or one) units when ACE is small.

4.4 Performance Criterion

The NYISO has established the following:

- generator performance measurement criterion, and
- procedures to disqualify Suppliers using Generators that consistently fail to meet the criterion.

4.4.1 Performance Tracking

The NYISO has a Performance Tracking System (PTS) to monitor the performance of Generators that provide Regulation service. Payments by the NYISO to each Supplier of this Service are based in part on the Generator's performance with respect to expectations. The PTS will also be used to determine penalties assessed to non-regulating generators that do not follow their RTD basepoints, thereby increasing the regulation burden.

[Figure 4.3](#) illustrates a regulating unit that has perfect performance and [Figure 4.4](#) illustrates a regulating unit with performance errors.

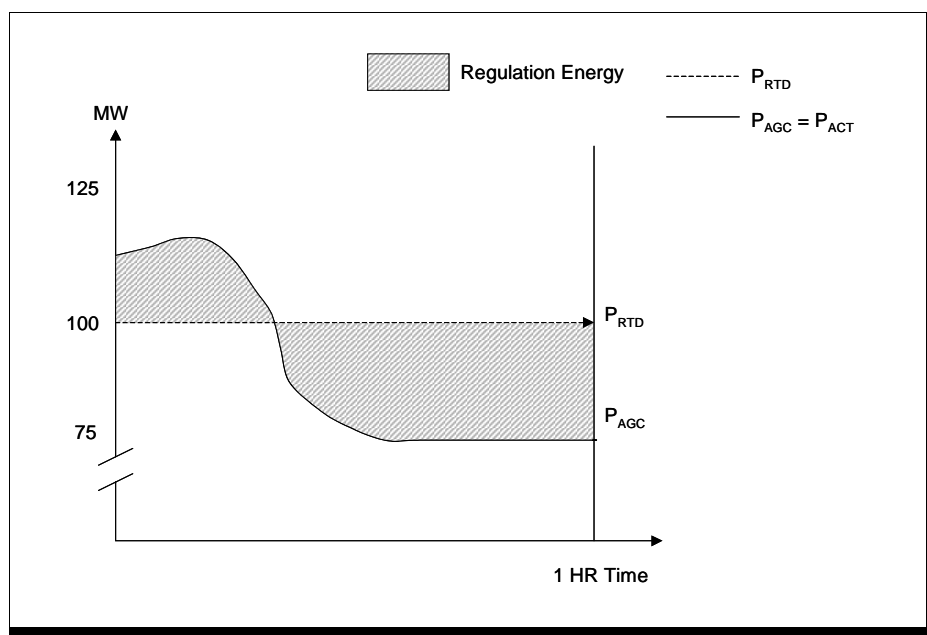


Figure 4.3: Perfect Performance

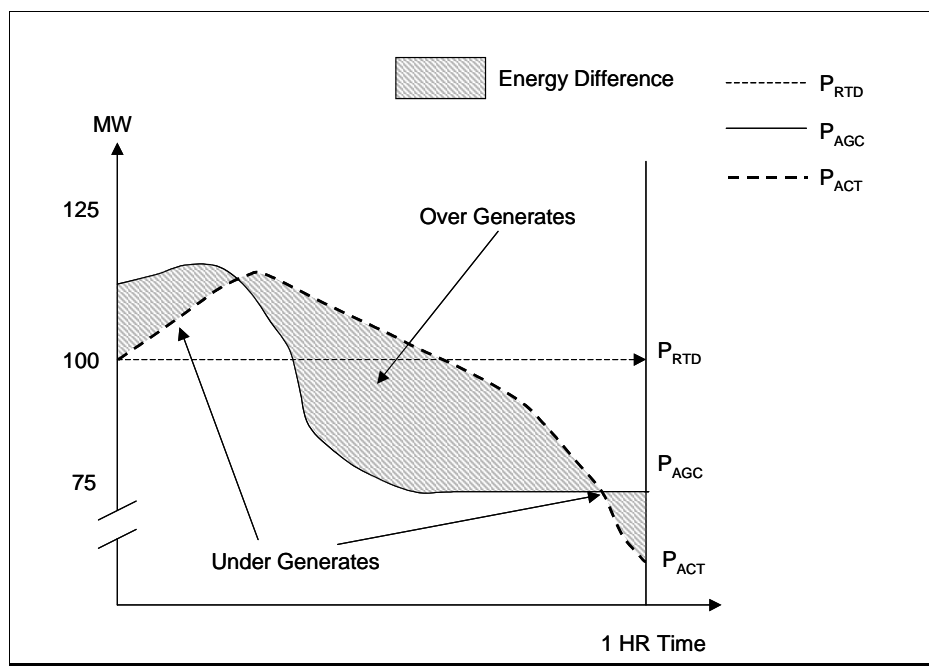


Figure 4.4: Error in Performance (30 Second bandwidth not included)

Regulation resources are required to change their output level at a rate consistent with the amount of regulation each resource has been scheduled to provide.

Regulation resources will not receive additional payments for following AGC signals that call for them to provide more regulation than they have been scheduled to provide; but they will be paid for any additional energy they produce as a result of following such signals.

Performance Adjustment

Attachment D of this Manual presents a detailed description of the calculation of regulation performance adjustments.

4.5 Regulation Service Settlements – Day-Ahead Market

4.5.1 Calculation of Day-Ahead Market Clearing Prices

The NYISO shall calculate a Day-Ahead Market clearing price for Regulation Service for each hour of the following day. The Day-Ahead Market clearing price for each hour shall equal the Day-Ahead Shadow Price for the NYISO's Regulation Service constraint for that hour, as described in Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT.

The Shadow Price takes account of the Day-Ahead Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or the applicable price on the Regulation Service Demand Curve during shortage conditions), plus any margins

on the sale of Energy or Operating Reserves in the Day-Ahead Market that the Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Operating Reserves. The Shadow Price also takes account of the Regulation Service Demand Curves described below, which will ensure that Regulation Service is not scheduled by SCUC at a cost greater than the Demand Curve indicates should be paid.

Each Supplier that is scheduled Day-Ahead to provide Regulation Service is paid the Day-Ahead Market clearing price in each hour, multiplied by the amount of Regulation Service that it is scheduled to provide for that hour.

4.5.2 Other Day-Ahead Payments

As provided in Section 4 and Attachment C of the NYISO Services Tariff, the NYISO shall compensate each ISO-Committed Flexible Generator that provides Regulation Service if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Day-Ahead Market, including start-up costs, minimum load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services.

No payments shall be made to any Supplier providing Regulation Service in excess of the amount of Regulation Service scheduled by the NYISO in the Day-Ahead Market, except to the extent that a Supplier is directed to provide the excess amount by the NYISO.

4.6 Regulation Service Settlements – Real-Time Markets

4.6.1 Calculation of Real-Time Market Clearing Prices

The NYISO shall calculate a Real-Time Market clearing price for Regulation Service for every RTD interval, except as noted in Section 4.10 of this Manual. Normally, the Real-Time Market clearing price for each interval shall equal the real-time Shadow Price for the NYISO's Regulation Service constraint for that RTD interval. Calculation of the Real-Time Market Clearing Price (MCP) during EDRP/SCR events is set forth in Section 4.6.2.

The Real-Time MCP for each RTD interval shall equal the Real-Time Shadow Price for the NYISO's Regulation Service constraint for that interval, as described in Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT.

The Shadow Price takes account of the Real-Time Regulation Service Bid of the marginal Resource selected to provide Regulation Service (or the applicable price on the Regulation Service Demand Curve during shortage conditions), plus any margins on the sale of Energy or Operating Reserves in the Real-Time Market that the Resource would forego if scheduling it to provide additional Regulation Service would lead to it being scheduled to provide less Energy or Regulation. The Shadow Price also takes account of the Regulation Service Demand Curves described in Section 4.8 of this Manual, which will ensure that Regulation Service is not

scheduled by RTC at a cost greater than the Demand Curve indicates should be paid.

Each supplier that is scheduled in Real-Time to provide Regulation Service is paid the Real-Time MCP, for each RTD interval multiplied by the amount of Regulation Service that it is scheduled to provide during that interval.

4.6.2 Calculation of Real-Time Market Clearing Prices for Regulation Service during EDRP/SCR Activations

During any interval in which the NYISO is using scarcity pricing rule “A” or “B” to calculate LBMPs under Section I.A.2.a or 2.b of Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT, the real-time Regulation Service market clearing price may be recalculated in light of the Availability Bids and Lost Opportunity Costs of Generators scheduled to provide Regulation Service in real-time.

Specifically, when either scarcity pricing rule is applicable, the real-time Regulation Service clearing price shall be set to the higher of:

1. The highest total Availability Bids and Lost Opportunity Cost of any Regulation Service provider scheduled by RTD
2. The Market clearing price calculated under Section 4.6.1 of this Manual.

4.6.3 Real-Time Regulation Service Balancing Payments

Any deviation from a Generator’s Day-Ahead schedule to provide Regulation Service shall be settled pursuant to the following rules:

1. When the Supplier’s real-time Regulation Service schedule is less than its Day-Ahead Regulation Service award, the Generator shall pay a charge for the imbalance equal to the product of:
 - a. The Real-Time Market clearing price for Regulation Service
 - b. The difference between the Generator’s Day-Ahead Regulation Service schedule and its real-time Regulation Service schedule
2. When the Generator’s real-time Regulation Service schedule is greater than its Day-Ahead Regulation Service schedule, the NYISO shall pay the Generator an amount to compensate it for the imbalance equal to the product of:
 - a. The Real-Time Market clearing price for Regulation Service
 - b. The difference between the Generator’s Day-Ahead Regulation Service schedule and its real-time Regulation Service schedule

4.6.4 Other Real-Time Regulation Service Payments

As is provided in Section 4 and Attachment C of the NYISO Services Tariff, the NYISO shall compensate each ISO-Committed Flexible Generator that provides Regulation Service if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Real-Time Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the

sale of Energy and Ancillary Services.

No payments shall be made to any Generator providing Regulation Service in excess of the amount of Regulation Service scheduled by the NYISO in the Real-Time Market, except to the extent that a Generator is directed to provide the excess amount by the NYISO.

Finally, whenever a Generator's real-time Regulation Service schedule is reduced by the NYISO to a level lower than its Day-Ahead schedule for that product, the Generator's Day-Ahead Margin shall be protected after accounting for any margin associated with other products that the Generator is scheduled to provide in real-time. The rules governing the calculation of these Day-Ahead Margin Assurance Payments are set forth in Attachment J to the NYISO Services Tariff. In addition, Attachment E of this Manual provides additional information on performance-based adjustments to regulation service payments.

4.7 Energy Settlement Rules for Generators Providing Regulation Service

4.7.1 Energy Settlements

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is different than its RTD Base Point Signal, the Generator shall receive a settlement payment for Energy consistent with a real-time Energy injection equal to the lower of its actual generation or its AGC Base Point Signal.

4.7.2 Additional Payments/Charges When AGC Base Point Signals Exceed RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is higher than its RTD Base Point Signal, it shall receive or pay a Regulation Revenue Adjustment Payment (RRAP) or Regulation Revenue Adjustment Charge (RRAC) calculated under the terms of this subsection. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall receive a RRAP. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at its location at that interval, the Generator shall be assessed a RRAC. RRAPs and RRACs shall be calculated using the following formula:

$$p_1 = \text{RTDBasePointSignal}$$

$$p_2 = \max[\text{RTDBasePointSignal}, \min(\text{AGCBasePointSignal}, \text{ActualOutput})]$$

$$\text{Payment/Charge} = \left(\frac{s}{3600} \right) \times \int_{p_1}^{p_2} (\text{Bid}(p) - \text{LBMP}) dp$$

Where:

- s is the number of seconds in the RTD interval;

If the result of the calculation is positive, then the Generator shall receive a RRAP. If it is negative, then the Generator shall be subject to a RRAC. For purposes of applying this formula, whenever the Generator's actual Bid exceeds the applicable LBMP the "Bid" term shall be set at a level equal to the lesser of the Generator's actual Bid or its reference Bid plus \$100/MWh.

4.7.3 Additional Charges/Payments When AGC Base Point Signals are Lower than RTD Base Point Signals

For any interval in which a Generator that is providing Regulation Service receives an AGC Base Point Signal that is lower than its RTD Base Point Signal, it shall receive or pay a RRAP or RRAC calculated under the terms of this subsection. If the Energy Bid Price of such a Generator is higher than the LBMP at its location in that interval, the Generator shall be assessed a RRAC. Conversely, for any interval in which such a Generator's Energy Bid Price is lower than the LBMP at its location in that interval, the Generator shall receive a RRAP. RRAPs and RRACs shall be calculated using the following formula:

$$p_1 = \min[\text{RTDBasePointSignal}, \max(\text{AGCBasePointSignal}, \text{ActualOutput})]$$

$$p_2 = \text{RTDBasePointSignal}$$

$$\text{Payment/Charge} = \left(\frac{s}{3600} \right) \times \int_{p_1}^{p_2} (\text{Bid}(p) - \text{LBMP}) dp$$

Where:

- s is the number of seconds in the RTD interval;

If the result of the calculation is positive, then the Generator shall receive a RRAP. If it is negative then the Generator shall be subject to a RRAC. For purposes of this formula, whenever the Generator's actual Bid is lower than the applicable LBMP the "Bid" term shall be set at a level equal to the higher of the Generator's actual Bid or its reference Bid minus \$100/MWh.

4.8 Regulation Service Demand Curve

The NYISO shall establish a Regulation Demand Curve that will apply to both the Day-Ahead and Real-Time Regulation Service markets. The market clearing prices for Regulation Service calculated pursuant to Sections 4.5.1 and 4.6.1 of this Manual shall take account of the demand curve established in this Section so that Regulation Service is not purchased at a cost higher than the demand curve indicates should be paid in the relevant market.

The NYISO shall establish a target level of Regulation Service for each hour, which will be the number of MW of Regulation Service that the NYISO would seek to maintain in that hour if cost were not a consideration. The NYISO will then define a Regulation Service demand curve for that hour as follows:

1. For quantities of Regulation Service that are less than or equal to the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be \$300/MW.
2. For quantities of Regulation Service that are less than equal to the target level of Regulation Service but that exceed the target level of Regulation Service minus 25 MW, the price on the Regulation Service demand curve shall be \$250/MW.
3. For all other quantities, the price on the Regulation Service demand curve shall be \$0/MW. However, the NYISO shall not schedule more Regulation Service than the target level for the requirement for that hour.

In order to respond to operational or reliability problems that arise in Real-Time, the NYISO may procure Regulation Service at a quantity and/or price point different from those specified above. The NYISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The NYISO shall also investigate whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The NYISO will consult with its Market Advisor when it conducts this investigation.

If the NYISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the NYISO will consult with its Market Advisor, the Business Issues Committee, the Commission, and the PSC before implementing any such modifications. In all circumstances, the NYISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Regulation Service Demand Curve, the NYISO, in consultation with its Market Advisor, shall conduct an initial review in accordance with the NYISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether the Regulation Service Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the NYISO-Administered Markets. The NYISO and the Market Advisor shall perform additional quarterly reviews, subject to the same scope requirement, during the remainder of the first year that this Section 4.8 is in effect. After the first year, the NYISO and the Market Advisor shall perform periodic reviews, subject to the same scope requirement.

4.9 Reinstating Performance Charges

The NYISO will monitor, on a Real-Time hourly or daily basis, as appropriate, its compliance with the standards established by NERC and NPCC and with the standards of Good Utility Practice for Control Performance, Area Control Area, Disturbance Control Standards, Reserve Pickup Performance, and System Security. Should it appear to the NYISO that degradation in performance threatens compliance with one or more of the established standards for these criteria or compromises reliability, and that reinstating the performance charges that were originally part of the NYISO's market design, would assist in improving compliance with established standards for these criteria, or would assist in re-establishing reliability, the NYISO may require Suppliers of Regulation Service, as well as Suppliers not providing Regulation Service, to pay a performance charge.

Any reinstatement of Regulation penalties pursuant to this Section shall not override previous Commission-approved settlement agreements that exempt a particular unit from such penalties. The NYISO shall provide notice of its decision to reinstate performance charges to the Commission, to each Customer and to the Operating Committee and the Business Issues Committee no less than seven days before it re-institutes the performance charges.

If the NYISO determines that performance charges are necessary, Suppliers of Regulation Service shall pay a performance charge to the NYISO as follows:

$$\text{Performance Charge} = \text{Energy Deviation} * \text{MCP}_{\text{reg}} * (\text{Length of Interval}/60 \text{ minutes})$$

Where:

- Energy Deviation (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy required by the AGC Base Point Signals, whether positive or negative, averaged over each RTD interval; and
- MCP_{reg} is the Market Clearing Price (\$/MW), which applies to the RTD interval for this Service in the Real-Time Market or the Day-Ahead Market, if appropriate.

The method used by the NYISO to calculate the Energy Deviation will permit Suppliers a certain period of time to respond to AGC Base Point Signals. Initially this time period will be 30 seconds, although the NYISO will have the authority to change its length. If the Supplier's output at any point in time is between the largest and the smallest of the AGC Base Points sent to that Supplier within the preceding 30 seconds (or such other time period length as the NYISO may define), the Supplier's Energy Deviation at that point in time will be zero.

Otherwise, the Supplier may have a positive Energy Deviation. However, in cases in which responding to the AGC Base Point within that time period would require a Supplier to change output at a rate exceeding the amount of Regulation it has been scheduled to provide, the Supplier will have a zero Energy Deviation if it changes output at the rate equal to the amount of Regulation it is scheduled to provide.

4.10 Temporary Suspension of Regulation Service Markets During Reserve Pick-Up

During any period in which the NYISO has activated RTD-CAM software and has called for a “large event” or “small event” reserve or maximum generation pick-up, as described in Section 4 of the NYISO Services Tariff, the NYISO will suspend Generators’ obligation to follow the AGC Base Point Signals sent to Regulation Service providers and will suspend the Real-Time Regulation Service market. The NYISO will not procure any Regulation Service and will establish a Real-Time Regulation Service Market clearing price of zero for settlement and balancing purposes. The NYISO will resume sending AGC Base Point Signals and restore the Real-Time Regulation Service market as soon as possible after the end of the reserve or maximum generation pickup.

4.11 Charges Applicable to Suppliers That Are Not Providing Regulation Service

4.11.1 Persistent Under-generation Charges

An Energy Supplier that is not providing Regulation Service and that persistently operates at a level below its schedule shall pay a persistent under-generation charge to the NYISO, unless its operation is within a tolerance described below. Persistent under-generation charges shall be calculated as follows:

Persistent under-generation charge = Energy Difference * MCP_{reg} * Length of Interval/60 Minutes
Where:

- Energy Difference in (MW) is determined by subtracting the actual Energy provided by the Supplier from its RTD Base Point for the dispatch interval. The Energy Difference shall be set at zero for any Energy Difference that is otherwise negative or that falls within a tolerance, set pursuant to NYISO Procedures, and which shall contain a steady-state and a dynamic component. The steady-state component shall be 3% of the Supplier’s Normal Upper Operating Limit or Emergency Upper Operating Limit, as applicable, and the dynamic component shall be a time constant that shall initially be set at fifteen minutes; and
- MCP_{reg} is the Market-Clearing Price (\$/MW) which applies to the dispatch interval for which Regulation Service in the Real-Time Market, or, if applicable, the Day-Ahead Market.

4.11.2 Restoration of Performance Charges

The persistent under-generation charges described above shall be suspended in the event that the NYISO re-institutes Regulation performance charges. If the NYISO re-institutes performance charges then Suppliers that sell Energy through the LBMP Markets or that supply Bilateral Transactions that serve Load in the NYCA, but that

do not provide Regulation Service, shall pay a performance charge to the NYISO as follows:

$$\text{Performance Charge} = \text{Energy Difference} * \text{MCPreg} * \text{Length of Interval}/60 \text{ minutes}$$

Where:

- Energy Difference (in MW) is the absolute difference between the actual Energy supplied by the Supplier and the Energy it is directed to produce by its RTD Base Point Signals, whether positive or negative, averaged over each RTD interval; and
- MCPreg is the Market Clearing Price (\$/MW), which applies to the interval for which Regulation Service was provided in the Real-Time Market, or, if appropriate, the Day-Ahead Market.

In cases in which the Energy Difference that would be calculated using the procedure described above is less than 3%, the NYISO shall set the Energy Difference for that interval equal to zero.

4.11.3 Exemptions

The following types of Generator shall not be subject to persistent under-generation charges, or, if they are restored by the NYISO, to performance charges:

- Generators providing Energy under contracts (including PURPA contracts), executed and effective on or before November 18, 1999, in which the power purchaser does not control the operation of the supply source but would be responsible for payment of the persistent under-generation or performance charge
- Existing topping turbine Generators and extraction turbine Generators producing electric Energy resulting from the supply of steam to the district steam system in operation on or before November 18, 1999 and/or topping or extraction turbine Generators utilized in replacing or repowering existing steam supplies from such units (in accordance with good engineering and economic design) that cannot follow schedules, up to a maximum total of 365 MW of such units;
- Existing intermittent (i.e., non-schedulable) renewable resource Generators within the NYCA in operation on or before November 18, 1999, plus up to an additional 500 MW of such Generators; and
- Capacity Limited Resources and Energy Limited Resources to the extent that their Real-Time Energy injections are equal to or greater than their bid-in upper operating limits but are less than their Real-Time Scheduled Energy Injections.

Note: This exemption does not apply to points 1, 2, and 3 above, in an hour if the Generator or Resource has bid in that hour as ISO-Committed Flexible or Self-Committed Flexible.

4.12 Charges to Load Serving Entities

All LSEs taking service under the NYISO OATT pay a charge for this Service on all Bilateral Transactions and purchases in the LBMP Markets to serve Load located in the NYCA. The NYISO calculates the charge, for each hour, by summing:

- **Supplier Payment** – the aggregate payments made by the NYISO to all Suppliers of this Service.
- **Supplier Charge** – the aggregate of charges paid by all Regulation Providers.
- **Non-Regulating Generator Charge** – the aggregate of charges paid by all Generators.

In any hour where the charges paid by Generators and Suppliers exceed the payments made to Suppliers of Regulation service:

- The NYISO will not assess a charge against any LSE.
- Additionally, the surplus will be applied to the following hour as an offset to subsequent payments.

Otherwise, these charges are allocated to each LSE in the NYCA in proportion to its load ratio share for that hour. Charges that are paid by LSEs for this Service are aggregated to render a monthly charge.

4.13 Regulation & Frequency Response Notification Procedures

The following procedures are for notifying suppliers in the event that they exhibit poor “Regulation and Frequency Response” performance.

In the initial LBMP implementation, these procedures will be performed at the end of each billing cycle.

NYISO Actions

The NYISO shall perform the following:

- Notify the poor performing supplier via telephone or E-mail, upon determination by the NYISO that the supplier is exhibiting poor performance.
- Notify the poor performing supplier that they are currently being penalized as described in the *NYISO Accounting and Billing Manual*, and that persistent non-compliance in accordance with this procedure will result in additional penalties and that consistent or continued poor performance will result in the provider being removed from the bidders list.

Regulation Provider Actions

The poor performer shall acknowledge the NYISO notification and report their expectation of the time they will be able to return to normal performance. The provider shall also describe the cause of their poor performance.

6. OPERATING RESERVE SERVICE

6.1 Description

Operating Reserve service provides backup generation in the event that major Generating Resources trip off-line due to either a power system Contingency or equipment failure. In order for the New York Control Area (NYCA) to respond in a timely fashion, the reserves must be available from units within the NYCA and within specific regions, as required by the NYSRC.

Types of Operating Reserves:

- 10-Minute Spinning Reserve — Operating Reserves provided by qualified Generators and qualified Interruptible/Dispatchable Load Resources located within the NYCA that are already synchronized to the NYS Power System and can respond to instructions from the NYISO to change output level within 10 minutes.
- 10-Minute Non-Synchronized Reserve (10-Minute NSR) — Operating Reserves provided by Generators that can be started, synchronized, and loaded within 10 minutes. These reserves are carried on quick-start units, such as jet engine type gas turbines.
- 30-Minute Spinning Reserve - Operating Reserves provided by qualified Generators and qualified Interruptible/Dispatchable Load Resources located within the NYCA that are already synchronized to the NYS Power System and can respond to instructions from the NYISO to change output level within 30 minutes.
- 30-Minute Non-Synchronized Reserve (30-Minute NSR) – Operating reserves that can be provided by Generators that can be started, synchronized, and loaded within 30 minutes.
- Total 10-Minute Reserve — The sum of the 10-Minute Spinning Reserve and 10-Minute NSR. [NERC defines this as Contingency Reserve]
- Total 30-Minute Reserve – The sum of the 30-minute Spinning Reserve and 30-Minute NSR provided by Generators and interruptible/dispatchable load resources that respond to instructions to change output energy within 30 minutes.
- Total Operating Reserve — The sum of the total 10-minute reserve and the total 30-minute reserve. [The NERC definition of operating reserve includes regulation]

Minimum Operating Reserve Requirement:

The NYCA's Operating Reserve requirements are:

- Total Operating Reserve must be greater than or equal to one and one-half times the largest single Contingency (in MW) as defined by the NYISO;
- Total 10-Minute Reserve must be greater than or equal to the largest single Contingency (in MW) as defined by the NYISO;
- 10-Minute Spinning Reserve must be greater than or equal to one-half of the largest single Contingency (in MW) as defined by the NYISO.
- [Figure 6.1](#) illustrates these requirements. At all times sufficient total 10-minute reserve is maintained to cover the energy loss due to the most severe Normal Transfer Criteria

contingency within the NYCA or the energy loss caused by the cancellation of an interruptible export transaction (NYCA to neighboring control area) whichever is greater. In addition:

- The NYISO may establish additional categories of Operating Reserves if necessary to ensure reliability.
- The NYISO ensures that providers of Operating Reserves are properly located electrically so that transmission constraints resulting from either commitment or dispatch of units do not limit the ability to deliver Energy to Loads in the case of a Contingency.
- The NYISO ensures that Capacity counted toward meeting NYCA Operating Reserve requirements is not counted toward meeting Regulation and Frequency Response Service requirements.

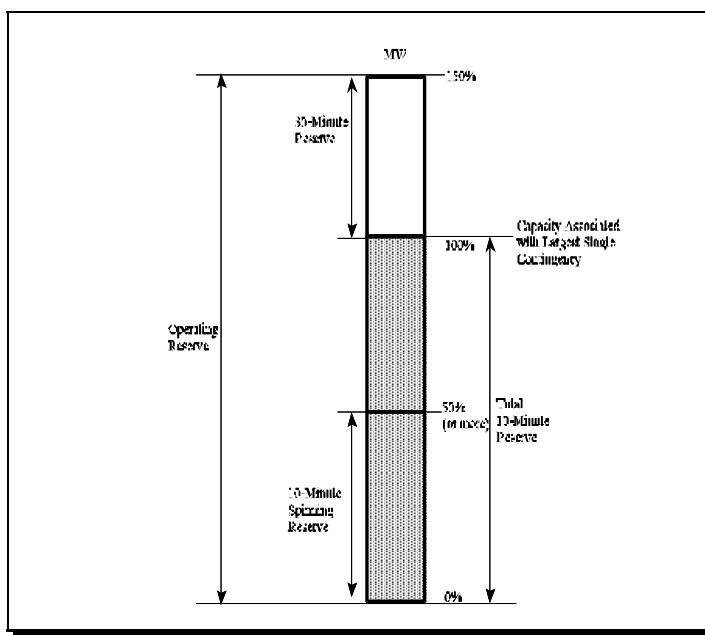


Figure 6.1: Operating Reserve Requirements

6.2 General Responsibilities and Requirements

The NYISO is responsible for scheduling the Operating Reserve service. The NYISO ensures that Operating Reserve is properly geographically located so that transmission constraints do not limit the ability to deliver Operating Reserve. Reserve suppliers receive both a Day-Ahead and a Real-Time schedule. The Real-Time schedule may differ from the Day-Ahead schedule. Reserve suppliers must specify a Day-Ahead availability bid for each category of reserve. The Real-Time availability bid is automatically set to zero for each category of reserve and cannot be changed by a reserve supplier. [Table 6.1](#) summarizes supplier eligibility to provide ancillary services of reserve and regulation.

Table 6.1: Ancillary Service Eligibility

Unit Type	Ancillary Service				
	10-S	10-NS	30-S	30-NS	Reg
Flexible (on-dispatch) Start-up time greater than 30 minutes Not block loaded	✓	no	✓	no	✓
Flexible (on-dispatch) 10-minute start Not block loaded	✓	✓	✓	no	✓
Flexible (on-dispatch) 10-minute start Block loaded (no dispatchable range)	no	✓	no	no	no
Flexible (on-dispatch) 30-minute start Not block loaded	✓	no	✓	✓	✓
Flexible (on-dispatch) 30-minute start Block loaded (no dispatchable range)	no	no	no	✓	no
Fixed (off-dispatch)	no	no	no	no	no

6.2.1 NYISO Responsibilities

The NYISO shall procure on behalf of its Customers a sufficient quantity of Operating Reserve products to comply with the Reliability Rules and with other applicable reliability standards. To the extent that the NYISO enters into Operating Reserve sharing agreements with neighboring Control Areas its Operating Reserves requirements shall be adjusted accordingly.

The NYISO shall define requirements for Spinning Reserve, which may be met only by Suppliers that are eligible to provide Spinning Reserve; 10-Minute Reserve, which may be met by Suppliers that are eligible to provide either Spinning Reserve or 10-Minute Non-Synchronized Reserve; and 30-Minute Reserve, which may be met by Suppliers that are eligible to provide any Operating Reserve product. The NYISO shall also define locational requirements for Spinning Reserve, 10-Minute Reserve, and 30-Minute Reserve located East of Central East and on Long Island as shown in [Table 6.2](#).

Table 6.2: NYISO Locational Reserve Requirements

	New York CA	Eastern New York	Long Island
	A = most severe NYCA operating capability loss (1200MW)		
10 Minute Spinning Reserve	$\frac{1}{2} A = 600\text{MW}$ (I)	$\frac{1}{4} A = 300\text{MW}$ (IV)	$\frac{1}{20} A = 60\text{MW}$ (VII)
10 Minute Total Reserve	$A = 1200\text{MW}$ (II)	1200MW (V)	$\frac{1}{10} A = 120\text{MW}$ (VIII)
30 Minute Reserve	$1\frac{1}{2} A = 1800\text{MW}$ (III)	1200MW (VI)	$270\text{-}540\text{MW}$ (IX)
<p>I. NYCA 10-minute spinning reserve is equal to at least one-half of the 10-minute total reserve. [NYS RC Operating Reliability Rules].</p> <p>II. NYCA 10-minute total reserve is equal to the operating capability loss caused by the most severe contingency under normal transfer conditions. [NYS RC Operating Reliability Rules].</p> <p>III. NYCA 30-minute total reserve is equal to one and one-half the 10-minute reserve necessary to replace the operating capability loss caused by the most severe contingency under normal transfer conditions. [NYS RC Operating Reliability Rules].</p> <p>IV. ENY 10-minute spinning reserve is based on the NERC requirement that operating reserves should be dispersed throughout and shall consider the effective use of such in an emergency, time to be effective, transmission limitations, and local area requirements. [NERC OP1]</p> <p>V. ENY 10-minute total reserve is based on Reliability Rules that require immediate measures (activation of ENY 10-minute reserves) be applied to bring loadings on an internal NY transfer interface to within limits in 15 minutes. [NYS RC Operating Reliability Rules].</p> <p>VI. ENY 30-minute total reserve is based on the NERC requirement that operating reserves should be dispersed throughout and shall consider the effective use of such in an emergency, time to be effective, transmission limitations, and local area requirements. [NERC OP1]</p> <p>VII. LI 10-minute spinning reserve is based on the NERC requirement that operating reserves should be dispersed throughout and shall consider the effective use of such in an emergency, time to be effective, transmission limitations, and local area requirements. [NERC OP1]</p> <p>VIII. LI 10-minute total reserve is based on the NERC requirement that operating reserves should be dispersed throughout and shall consider the effective use of such in an emergency, time to be effective, transmission limitations, and local area requirements. [NERC OP1]</p> <p>IX. LI 30-minute total reserve is based on ISO Reliability Rules that require the ability to restore a transmission circuit loading to Normal Operating Criteria within 30 minutes of the contingency. The LI 30-minute reserve requirement will vary from 270MW for off-peak hours to 540MW for on-peak hours. [NYS RC Reliability Rules]</p>			

In addition to being subject to the preceding limitations on Suppliers that can meet

each of these requirements, the requirements for Operating Reserve located East of Central East may only be met by eligible Suppliers that are located East of Central East, and requirements for Operating Reserve located on Long Island may only be met by eligible Suppliers located on Long Island. Each of these Operating Reserve requirements shall be defined consistent with the Reliability Rules and other applicable reliability standards. The NYISO shall select Suppliers of Operating Reserves products to meet these requirements, including the locational Operating Reserves requirements, as part of its overall co-optimization process.

The NYISO shall select Operating Reserves Suppliers that are properly located electrically so that all locational Operating Reserves requirements are satisfied, and so that transmission constraints resulting from either the commitment or dispatch of Generators do not limit the NYISO's ability to deliver Energy to Loads in the case of a Contingency. The NYISO will ensure that Suppliers that are compensated for using Capacity to provide one Operating Reserve product are not simultaneously compensated for providing another Operating Reserve product, or Regulation Service, using the same Capacity.

6.2.2 Supplier Eligibility Criteria

The NYISO shall enforce the following criteria, which define which types of Generators or Demand Side Resources are eligible to supply particular Operating Reserve products.

1. ***Spinning Reserve*** – Generators that are ISO-Committed Flexible or Self-Committed Flexible; are operating within the dispatchable portion of their operating range; are capable of responding to NYISO instructions to change their output level within ten minutes, and are capable of producing Energy for at least thirty minutes, shall be eligible to supply Spinning Reserve.
2. ***10-Minute Non-Synchronized Reserve*** – Off-line Generators that are capable of starting, synchronizing, and increasing their output level within ten minutes and that meet the criteria set forth in the NYISO Procedures, and, when the NYISO has the capability to support their participation, Demand Side Resources that are capable of reducing their Energy usage within ten minutes and that meet the criteria set forth in the NYISO Procedures, shall be eligible, provided that they are capable of providing Energy for at least thirty minutes, to supply 10-Minute Non-Synchronized Reserve.
3. ***30-Minute Reserve (spinning and non-synchronized)*** – (i) Generators that are ISO-Committed Flexible or Self-Committed Flexible and operating within the dispatchable portion of their operating range shall be eligible to supply synchronized 30-Minute Reserves; (ii) Off-line Generators that are capable of starting, synchronizing, and increasing their output level within thirty minutes and that meet the criteria set forth in the NYISO Procedures, and, when the NYISO has the capability to support their participation, Demand Side Resources that are capable of reducing their Energy usage within thirty minutes and that meet the criteria set forth in the NYISO Procedures, shall be eligible to supply non-synchronized 30-Minute Reserves.

4. *Self-Committed Fixed and ISO-Committed Fixed Generators* – Shall not be eligible to provide any kind of Operation Reserve.

6.2.3 Other Supplier Requirements

All Suppliers of Operating Reserve must be located within the NYCA and must be under NYISO Operational Control. Each Supplier bidding to supply Operational Reserve or reduce demand must be able to provide Energy or reduce demand consistent with the Reliability Rules and the NYISO Procedures when called upon by the NYISO. All Suppliers that are selected to provide Operating Reserve shall ensure that their Resources maintain and deliver the appropriate quantity of Energy, or reduce the appropriate quantity of demand, when called upon by the NYISO during any interval in which they have been selected.

Generators or Demand Side Resources that are selected to provide Operating Reserve in the Day-Ahead Market or any supplemental commitment may not increase their Energy Bids or Demand Reduction Bids for portions of their Resources that have been scheduled through those processes, or reduce their commitments, in Real-Time except to the extent that they are directed to do so by the NYISO. Generators and Demand Side Resources may enter into alternate sales arrangements utilizing any Capacity that has not been scheduled to provide Operating Reserve.

6.3 General Day-Ahead Market Rules

6.3.1 Bidding and Bid Selection

Resources capable of providing Spinning Reserve, 10-Minute Non-Synchronized Reserve, and/or 30-Minute Reserve (spinning and non-synchronized) in the Day-Ahead commitment may submit Availability Bids for each hour of the upcoming day. If a Supplier offers Resources that are capable, based on their indicated commitment status, of providing Operating Reserves but does not submit an Availability Bid, its Day-Ahead bid will be rejected in its entirety. A supplier may resubmit a complete Day-Ahead Bid, provided that the new bid is timely. The same rules shall apply to Demand Side Resources capable of providing 10-Minute Non-Synchronized Reserve and/or non-synchronized 30-Minute Reserve when the NYISO has the capability to support their participation in Operating Reserves market. Refer to [Table 6.1](#).

The NYISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels:

1. For Spinning Reserves, the Resource's emergency response rate multiplied by ten.
2. For 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E , whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid).

3. For synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by 20. This represents the amount of spinning reserve, above and beyond 10-minute spinning reserve, that the Resource could convert to energy within 30 minutes.

However, the sum of the amount of Energy or Demand Reduction each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed UOL_N or UOL_E , whichever is applicable.

The NYISO shall select Operating Reserve Suppliers for each hour of the upcoming day through a co-optimized Day-Ahead commitment process that minimizes the total cost of Energy, Operating Reserves, and Regulation Service, using Bids submitted to the NYISO. As part of the co-optimization process, the NYISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

6.3.2 NYISO Notice Requirement

The NYISO shall notify each Operating Reserve Supplier that has been selected in the Day-Ahead Schedule of the amount of each Operating Reserve product that it has been scheduled to provide.

6.3.3 Responsibilities of Suppliers Scheduled to Provide Operating Reserves in the Day-Ahead Market

Suppliers that are scheduled Day-Ahead to provide Operating Reserves shall either provide Operating Reserve, or Energy, or, when the NYISO has the capability to support demand side participation, reduce demand in Real-Time when scheduled by the NYISO in all hours for which they have been selected to provide Operating Reserve and are physically capable of doing so. However, Suppliers that are scheduled Day-Ahead to provide Operating Reserves and have startup periods of two hours or less may advise the NYISO no later than three hours prior to the first hour of their Day-Ahead schedule that they will not be available to provide Operating Reserves or Energy in Real-Time under normal conditions. Such Suppliers will be required to settle their Day-Ahead schedule at Real-Time prices. The only restriction on Suppliers' ability to exercise this option is that all Suppliers with Day-Ahead Operating Reserves schedules must make the scheduled amount of Capacity available to the NYISO for dispatch in the RTD if the NYISO initiates a Supplemental Resource Evaluation.

6.4 General Real-Time Market Rules

6.4.1 Bid Selection

The NYISO will automatically select Operating Reserves Suppliers in Real-Time from eligible Resources, and when the NYISO has the capability to support their participation, Demand Side Resources, that submit Real-Time Bids. All Suppliers will automatically be assigned a Real-Time Operating Reserves Availability bid of \$0/MW. The NYISO may schedule Suppliers that make themselves available to provide Operating Reserves up to the following maximum Operating Reserve levels:

1. For Spinning Reserves, the Resource's emergency response rate multiplied by ten.
2. For 10-Minute Non-Synchronized Reserves, or for non-synchronized 30-Minute Reserves, the Resource's UOL_N or UOL_E , whichever is applicable at the relevant time (the Resource may offer one product or the other depending on the time required for it to start-up and synchronize to the grid).
3. For synchronized 30-Minute Reserves, the Resource's emergency response rate multiplied by 30.

However, the sum of the amount of Energy, or, when the NYISO has the capability to support demand side participation, Demand Reduction, that each Resource is scheduled to provide, the amount of Regulation Service it is scheduled to provide, and the amount of each Operating Reserves product it is scheduled to provide shall not exceed its UOL_N or UOL_E , whichever is applicable.

Suppliers will thus be selected based on their response rates, their applicable upper operating limit, and their Energy Bid (which will reflect their opportunity costs) through a co-optimized Real-Time commitment process that minimizes the total cost of Energy, Regulation Service, and Operating Reserves. As part of the process, the NYISO shall determine how much of each Operating Reserves product particular Suppliers will be required to provide in light of the Reliability Rules and other applicable reliability standards, including the locational Operating Reserves requirements specified above.

6.4.2 NYISO Notice Requirements

The NYISO shall notify each Supplier of Operating Reserve that has been selected by RTD of the amount of Operating Reserve that it must provide.

6.4.3 Obligation to Make Resources Available to Provide Operating Reserves

Any Resource that is eligible to supply Operating Reserves and that is made available to the NYISO for dispatch in Real-Time, must also make itself available to provide Operating Reserves.

6.4.4 Activation of Operating Reserves

All Resources that are selected by the NYISO to provide Operating Reserves shall respond to the NYISO's directions to activate in Real-Time.

6.4.5 Performance Tracking and Supplier Disqualifications

When a Supplier selected to supply Operating Reserves is activated, the NYISO shall measure and track its actual Energy production against its expected performance in Real-Time. The NYISO may disqualify Generators that consistently fail to provide Energy when called upon to do so in Real-Time from providing Operating Reserves in the future. If a Resource has been disqualified, the NYISO shall require it to pass a re-qualification test before accepting any additional Bids to supply Operating Reserves from it. Disqualification and re-qualification criteria shall be set forth in the NYISO Procedures.

6.5 Operating Reserve Settlements – General Rules

6.5.1 Establishing Locational Reserve Prices

Except as noted below, the NYISO shall calculate separate Day-Ahead Market and Real-Time Market prices for each of the three Operating Reserve products for each of three locations:

1. West of Central-East (West or Western)
2. East of Central-East Excluding Long Island (East or Eastern)
3. Long Island (L.I.).

The NYISO will thus calculate nine different locational Operating Reserve prices in both the Day-Ahead Market and the Real-Time Market.

6.5.2 Settlements Involving Suppliers of Operating Reserves Located on Long Island

Suppliers of Operating Reserves located on Long Island shall receive settlement payments as if they were providing Operating Reserves located in the East. The NYISO will calculate separate locational Long Island Operating Reserves prices but will not post them or use them for settlement purposes.

6.5.3 “Cascading” of Operating Reserves

The NYISO will deem Spinning Reserve to be the “highest quality” Operating Reserve, followed by 10-Minute Non-Synchronized Reserve and by 30-Minute Reserve (spinning and then non-synchronized). The NYISO shall substitute higher quality Operating Reserves in place of lower quality Operating Reserves, when doing so lowers the total as-bid cost, i.e., when the marginal cost for the higher quality

Operating Reserve product is lower than the marginal cost for the lower quality Operating Reserve product, and the substitution of a higher quality for the lower quality product does not cause locational Operating Reserve requirements to be violated. However, to the extent that reliability standards require the use of higher quality Operating Reserves, substitution cannot be made in the opposite direction.

The price of higher quality Operating Reserves will not be set at a price below the price of lower quality Operating Reserves in the same location. Thus, the price of Spinning Reserves will not be below the price for 10-Minute Non-Synchronized Reserves or 30-Minute Reserves and the clearing price for 10-Minute Non-Synchronized Reserves will not be below the clearing price for 30-Minute Reserves.

6.6 Operating Reserve Settlements – Day-Ahead Market

6.6.1 Calculation of Day-Ahead Market Clearing Prices

The NYISO shall calculate hourly Day-Ahead Market Clearing Prices for each Operating Reserve product at each location. Each Day-Ahead Market Clearing Price shall equal the sum of the relevant Day-Ahead locational Shadow Prices for that product in that hour, subject to the “cascading” of different quality reserve products described above.

The Day-Ahead Market Clearing Price for a particular Operating Reserve product in a particular location shall reflect the Shadow Prices associated with all of the NYISO-defined Operating Reserve requirements, including locational requirements, that a particular Operating Reserves product from a particular location may be used to satisfy in a given hour. The NYISO shall calculate Day-Ahead Market Clearing Prices using the following formulae:

Market clearing price for Western 30-minute reserve	$MCP_{30}^W = SP_1$
Market clearing price for Western 10-minute non-synchronized reserve	$MCP_{10N}^W = SP_1 + SP_2$
Market clearing price for Western 10-minute spinning reserve	$MCP_{10S}^W = SP_1 + SP_2 + SP_3$
Market clearing price for Eastern 30-minute reserve	$MCP_{30}^E = SP_1 + SP_4$
Market clearing price for Eastern 10-minute non-synchronized reserve	$MCP_{10N}^E = SP_1 + SP_2 + SP_4 + SP_5$
Market clearing price for Eastern 10-minute spinning reserve	$MCP_{10S}^E = SP_1 + SP_2 + SP_3 + SP_4 + SP_5 + SP_6$
Market clearing price for Long Island 30-minute reserve	$MCP_{30}^{LI} = SP_1 + SP_4 + SP_7$
Market clearing price for Long Island 10-minute non-synchronized reserve	$MCP_{10N}^{LI} = SP_1 + SP_2 + SP_4 + SP_5 + SP_7 + SP_8$
Market clearing price for Long Island 10-minute spinning reserve	$MCP_{10S}^{LI} = SP_1 + SP_2 + SP_3 + SP_4 + SP_5 + SP_6 + SP_7 + SP_8$

Where:

SP_1 = Shadow Price for total 30-Minute Reserve requirement constraint for the hour

SP_2 = Shadow Price for total 10-Minute Reserve requirement constraint for the hour

SP_3 = Shadow Price for total Spinning Reserve requirement constraint for the hour

SP_4 = Shadow Price for Eastern or L.I. 30-Minute Reserve requirement constraint for the hour

SP_5 = Shadow Price for Eastern or L.I. 10-Minute Reserve requirement constraint for the hour

SP_6 = Shadow Price for Eastern or L.I. Spinning Reserve requirement constraint for the hour

SP_7 = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the hour

SP_8 = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the hour

SP_9 = Shadow Price for Long Island Spinning Reserve requirement constraint for the hour

Day-Ahead locational shadow prices will be calculated by SCUC. Each hourly Day-Ahead Shadow Price for each Operating Reserves requirement shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that hour, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that hour, as calculated during the fifth SCUC pass described in Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT.

As a result, the Shadow Price for each Operating Reserves requirement shall include the Day-Ahead Availability Bid of the marginal Resource selected to meet the requirement (or the applicable price on the Operating Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Day-Ahead Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service.

Shadow Prices will also be consistent with the Operating Reserve Demand Curves, described below, which will ensure that Operating Reserves are not scheduled by SCUC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If more Operating Reserve of a particular quality than is needed is scheduled to meet a particular locational Operating Reserve requirement, the Shadow Price for that Operating Reserve requirement constraint shall be set at zero.

Each Supplier that is scheduled Day-Ahead to provide Operating Reserve shall be paid the applicable Day-Ahead Market Clearing Price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each hour.

6.6.2 Other Day-Ahead Payments

As is provided in Section 4 and Attachment C of the NYISO Services Tariff, the NYISO shall compensate each ISO-Committed Flexible Resource providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Day-Ahead Market, including start-up costs, minimum Load costs, and Availability Bids, exceeds the revenues it receives from the sale of Energy and Ancillary Services.

6.7 Operating Reserve Settlements – Real-Time Market

6.7.1 Calculation of Real-Time Market Clearing Prices

The NYISO shall calculate Real-Time Market clearing prices for each Operating Reserve product for each location in every interval. Except during SCR/EDRP activations, described below, each Real-Time market-clearing price shall equal the sum of the relevant Real-Time locational Shadow Prices for that product, subject to the “cascading” of different quality reserve products described above.

The Real-Time Market clearing price for a particular Operating Reserve product for a particular location shall reflect the Shadow Prices associated with all of the NYISO-defined Operating Reserve requirements, including locational requirements, that a particular Operating Reserves product from given location may be used to satisfy in a given interval. The NYISO shall calculate the Real-Time Market clearing price using the following formulae:

Market clearing price for Western 30-minute reserve	$MCP_{30}^W = SP_1$
Market clearing price for Western 10-minute non-synchronized reserve	$MCP_{10N}^W = SP_1 + SP_2$
Market clearing price for Western 10-minute spinning reserve	$MCP_{10S}^W = SP_1 + SP_2 + SP_3$
Market clearing price for Eastern 30-minute reserve	$MCP_{30}^E = SP_1 + SP_4$
Market clearing price for Eastern 10-minute non-synchronized reserve	$MCP_{10N}^E = SP_1 + SP_2 + SP_4 + SP_5$
Market clearing price for Eastern 10-minute spinning reserve	$MCP_{10S}^E = SP_1 + SP_2 + SP_3 + SP_4 + SP_5 + SP_6$
Market clearing price for Long Island 30-minute reserve	$MCP_{30}^{LI} = SP_1 + SP_4 + SP_7$
Market clearing price for Long Island 10-minute non-synchronized reserve	$MCP_{10N}^{LI} = SP_1 + SP_2 + SP_4 + SP_5 + SP_7 + SP_8$
Market clearing price for Long Island 10-minute spinning reserve	$MCP_{10S}^{LI} = SP_1 + SP_2 + SP_3 + SP_4 + SP_5 + SP_6 + SP_7 + SP_8$

Where:

SP_1 = Shadow Price for total 30-Minute Reserve requirement constraint for the interval

SP₂ = Shadow Price for total 10-Minute Reserve requirement constraint for the interval

SP₃ = Shadow Price for total Spinning Reserve requirement constraint for the interval

SP₄ = Shadow Price for Eastern or L.I. 30-Minute Reserve requirement constraint for the interval

SP₅ = Shadow Price for Eastern or L.I. 10-Minute Reserve requirement constraint for the interval

SP₆ = Shadow Price for Eastern or L.I. Spinning Reserve requirement constraint for the interval

SP₇ = Shadow Price for Long Island 30-Minute Reserve requirement constraint for the interval

SP₈ = Shadow Price for Long Island 10-Minute Reserve requirement constraint for the interval

SP₉ = Shadow Price for Long Island Spinning Reserve requirement constraint for the interval

Real-time locational Shadow Prices will be calculated by the NYISO's RTD. Each Real-Time Shadow Price for each Operating Reserves requirement in each RTD interval shall equal the marginal Bid cost of scheduling Resources to provide additional Operating Reserves to meet that requirement in that interval, including any impact on the Bid Production Cost of procuring Energy or Regulation Service that would result from procuring an increment of Operating Reserve to meet the requirement in that interval, as calculated during the third RTD pass described in Attachment B to the NYISO Service Tariff, and Attachment J to the NYISO OATT.

As a result, the Shadow Price for each Operating Reserves requirement shall include the Real-Time Availability Bid of the marginal Resource selected to meet that requirement (or the applicable price on the Operating Reserve Demand Curve for that requirement during shortage conditions), plus any margins on the sale of Energy or Regulation Service in the Real-Time Market that that Resource would forego if scheduling it to provide additional Operating Reserve to meet that requirement would lead to it being scheduled to provide less Energy or Regulation Service.

Shadow Prices will also be consistent with the Operating Reserve Demand Curves, described below, which will ensure that Operating Reserves are not scheduled by RTC at a cost greater than the relevant Operating Reserve Demand Curve indicates should be paid. If there is more Operating Reserve of the required quality than is needed to meet a particular locational Operating Reserve requirement then the Shadow Price for that Operating Reserve requirement constraint shall be zero.

Each Supplier that is scheduled in Real-Time to provide Operating Reserve shall be paid the applicable Real-Time Market clearing price, based on its location and the quality of Operating Reserve scheduled, multiplied by the amount of Operating Reserve that the Supplier is scheduled to provide in each interval.

6.7.2 Calculation of Real-Time Market Clearing Prices for Operating Reserves During EDRP/SCR Activations

Scarcity pricing rules A and B are invoked when SCR/EDRP resources are activated and, but for the SCR/EDRP resources, the NYCA would experience a shortage of reserve. Scarcity pricing rule A applies when, but for SCR/EDRP resources, the NYCA would experience a shortage of reserve. Scarcity pricing rule B applies when, but for SCR/EDRP resources, the eastern portion of the NYCA would experience a shortage of reserve.

Scarcity Pricing Rule “A”

During any interval in which the NYISO is using scarcity pricing rule “A” to calculate LBMPs under Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT, the Real-Time market clearing prices for some Operating Reserves products may be recalculated in light of the Lost Opportunity Costs of Resources that are scheduled to provide Spinning Reserves and 30-Minute Reserves in the manner described below. The NYISO shall also consider the Lost Opportunity Costs of Resources providing lower quality Operating Reserves to ensure that the “cascading” of different quality reserve products, described above, are not violated. Specifically:

1. The Eastern Spinning Reserve market clearing price shall be higher of:
 - a. The highest Lost Opportunity Cost of any provider of Spinning Reserves and 30-Minute Spinning Reserve that is scheduled by RTD and is not located on Long Island
 - b. The original market clearing price calculated under Section 6.7.1 above.
2. The Eastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of:
 - a. The highest Lost Opportunity Cost of any provider of spinning 30-Minute Reserve that is scheduled by RTD and is not located on Long Island
 - b. The original market clearing price calculated under Section 6.7.1 above.
3. The Eastern 30-Minute Reserve market clearing price shall be the higher of:
 - a. The highest Lost Opportunity Cost of any provider of spinning 30-Minute Reserve that is scheduled by RTD and is not located on Long Island
 - b. The original market clearing price calculated under Section 6.7.1 above.
4. The Western Spinning Reserve market clearing price shall be the higher of:
 - a. The highest Lost Opportunity Cost of any provider of Western Spinning Reserve Western Spinning 30-Minute Reserves that is scheduled by RTD
 - b. The original market clearing price calculated under Section 6.7.1 above.
5. The Western 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of:
 - a. The highest Lost Opportunity Cost of any provider of Western spinning and

- 30-Minute Reserve that is scheduled by RTD; and
- b. The original market clearing price calculated under Section 6.7.1 above.
- 6. The Western 30-Minute Reserve market clearing price shall be the higher of:
 - a. The highest Lost Opportunity Cost of any provider of Western spinning and 30-Minute Reserves that is scheduled by RTD
 - b. The original market clearing price calculated under Section 6.7.1 above.

Scarcity Pricing Rule “B”

During any interval in which the NYISO is using scarcity pricing rule “B” to calculate LBMPs under Attachment B to the NYISO Services Tariff, and Attachment J to the NYISO OATT, the Real-Time market clearing prices for some Operating Reserves products may be recalculated in light of the Lost Opportunity Costs of Resources scheduled to provide Spinning Reserves and 30-Minute Reserves in order to satisfy Eastern Operating Reserve requirements in the manner described below. The NYISO shall also consider the Lost Opportunity Costs of Resources providing lower quality Operating Reserves to ensure that the “cascading” of different quality reserve products, described above, are not violated. Specifically:

- 1. The Eastern Spinning Reserve market clearing price shall be the higher of:
 - a. The highest Lost Opportunity Cost of any provider of Eastern Spinning Reserve and 30-Minute Reserve that is scheduled by RTD and is not located on Long Island
 - b. The original market clearing price calculated under Section 6.7.1 above.
- 2. The Eastern 10-Minute Non-Synchronized Reserve market clearing price shall be the higher of:
 - a. The highest Lost Opportunity Cost of any provider of Eastern spinning and 30-Minute Reserve that is scheduled by RTD and is not located on Long Island
 - b. The original market clearing price calculated under Section 6.7.1 above.
- 3. The Eastern 30-Minute Reserve market clearing price shall be the higher of:
 - a. The highest Lost Opportunity Cost of any provider of Eastern spinning and 30-Minute Reserve that is scheduled by RTD and is not located on Long Island
 - b. The original market clearing price calculated under Section 6.7.1 above.

Real-Time Market clearing prices for Western Reserve shall not be affected under scarcity pricing rule “B.”

6.7.3 Operating Reserve Balancing Payments

Any deviation in performance from a Supplier's Day-Ahead schedule to provide Operating Reserves, including deviations that result from schedule modifications made by the NYISO, shall be settled pursuant to the following rules.

1. When the Supplier's Real-Time Operating Reserves schedule is less than its assigned Day-Ahead Operating Reserves schedule, the Supplier shall pay a charge for the imbalance equal to the product of:
 - a. The Real-Time Market clearing price for the relevant Operating Reserves Product in the relevant location; and
 - b. The difference between the Supplier's Day-Ahead and Real-Time Operating Reserves schedules.
2. When the Supplier's Real-Time Operating Reserves schedule is greater than its assigned Day-Ahead Operating Reserves schedule, the NYISO shall pay the Supplier an amount to compensate it for the imbalance equal to the product of:
 - a. The Real-Time Market Clearing Price for the relevant Operating Reserve product in the relevant location; and
 - b. The difference between the Supplier's Day-Ahead and Real-Time Operating Reserves schedules.

6.7.4 Other Real-Time Payments

The NYISO shall pay Generators that are selected to provide Operating Reserves, but are directed to convert to Energy production in Real-Time, the applicable Real-Time LBMP for all Energy they are directed to produce in excess of their Day-Ahead schedule.

As is provided in Section 4 and Attachment C of the NYISO Services Tariff, the NYISO shall compensate each ISO-Committed Flexible Supplier providing Operating Reserves if its Bid Production Cost to provide the Energy and Ancillary Services it is scheduled to supply in the Real-Time Market, including Minimum Generation Bid and Start-Up Bid costs, the revenues it receives from the sale of Energy and Ancillary Services. Any Supplier that provides Energy during a large event reserve pickup or a maximum generation event shall be eligible for a Bid Production Cost guarantee payment calculated solely for the duration of the large event reserve pickup or maximum generation pickup.

Finally, whenever a Resource's Real-Time Operating Reserves schedule is reduced by the NYISO to a level lower than its Day-Ahead schedule for that product, the Resource's Day-Ahead Margin shall be protected after accounting for any margin associated with other products that the Resource is scheduled to provide in Real-Time. The rules governing the calculation of these Day-Ahead Margin Assurance Payments are set forth in Attachment J to the NYISO Services Tariff.

6.8 Operating Reserve Demand Curves

The NYISO shall establish nine Operating Reserve Demand Curves, one for each Operating Reserves requirement. Specifically, there shall be a demand curve for:

1. Total Spinning Reserves
2. Eastern or Long Island Spinning Reserves
3. Long Island Spinning Reserves
4. Total 10-Minute Non-Synchronized Reserves
5. Eastern or Long Island 10-Minute Non-Synchronized Reserves
6. Long Island 10-Minute Non-Synchronized Reserves
7. Total 30-Minute Reserves
8. Eastern or Long Island 30-Minute Reserves
9. Long Island 30-Minute Reserves.

Each Operating Reserve Demand Curve will apply to both the Day-Ahead Market and the Real-Time Market for the relevant product and location.

The NYISO Procedures shall establish a target level for each Operating Reserves requirement for each hour, which will be the number of MW of Operating Reserves meeting that requirement that the NYISO would seek to maintain in that hour if cost were not a consideration. The NYISO will then define an Operating Reserves demand curve for that hour corresponding to each Operating Reserves requirement as follows:

1. ***Total Spinning Reserves*** – For quantities of Operating Reserves meeting the total Spinning Reserves requirement that are less than or equal to the target level for that requirement, the price on the total Spinning Reserves demand curve shall be \$500/MW. For all other quantities, the price on the total Spinning Reserves demand curve shall be \$0/MW.
2. ***Eastern or Long Island Spinning Reserves*** – For quantities of Operating Reserves meeting the Eastern or Long Island Spinning Reserves requirement that are less than or equal to the target level for that requirement, the price on the Eastern or Long Island Spinning Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern or Long Island Spinning Reserves demand curve shall be \$0/MW.
3. ***Long Island Spinning Reserves*** – For quantities of Operating Reserves meeting the Long Island Spinning Reserves requirement that are less than or equal to the target level for that requirement, the price on the Long Island Spinning Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long

Island Spinning Reserves demand curve shall be \$0/MW.

4. ***Total 10-Minute Reserves*** – For quantities of Operating Reserves meeting the total 10-minute reserves requirement that are less than or equal to the target level for that requirement, the price on the total 10-minute reserves demand curve shall be \$150/MW. For all other quantities, the price on the total 10-minute reserves demand curve shall be \$0/MW.
5. ***Eastern or Long Island 10-Minute Reserves*** – For quantities of Operating Reserves meeting the Eastern or Long Island 10-minute reserves requirement that are less than or equal to the target level for that requirement, the price on the Eastern or Long Island 10-minute reserves demand curve shall be \$500/MW. For all other quantities, the price on the Eastern or Long Island 10-Minute Reserves demand curve shall be \$0/MW.
6. ***Long Island 10-Minute Reserves*** – For quantities of Operating Reserves meeting the Long Island 10-minute reserves requirement that are less than or equal to the target level for that requirement, the price on the Long Island 10-minute reserves demand curve shall be \$25/MW. For all other quantities, the price on the Long Island 10-minute reserves demand curve shall be \$0/MW.
7. ***Total 30-Minute Reserves*** – For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that requirement minus 400 MW, the price on the total 30-Minute Reserves demand curve shall be \$200/MW. For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that requirement minus 200 MW but that exceed the target level for that requirement minus 400 MW, the price on the total 30-Minute Reserves demand curve shall be \$100/MW.

For quantities of Operating Reserves meeting the total 30-Minute Reserves requirement that are less than or equal to the target level for that requirement but that exceed the target level for that requirement minus 200 MW, the price on the total 30-Minute Reserves demand curve shall be \$50/MW. For all other quantities, the price on the total 30-Minute Reserves demand curve shall be \$0/MW. However, the NYISO will not schedule more total 30-Minute Reserves than the level defined by the requirement for that hour.

8. ***Eastern or Long Island 30-Minute Reserves*** – For quantities of Operating Reserves meeting the Eastern or Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that requirement, the price on the Eastern or Long Island 30-Minute Reserves demand curve shall be \$25/MW. For all other quantities, the price on the Eastern or Long Island 30-Minute Reserves demand curve shall be \$0/MW.
9. ***Long Island 30-Minute Reserves*** – For quantities of Operating Reserves meeting the Long Island 30-Minute Reserves requirement that are less than or equal to the target level for that requirement, the price on the Long Island 30-Minute Reserves demand curve shall be \$300/MW. For all other quantities, the price on the Long Island 30-Minute Reserves demand curve shall be \$0/MW.

In order to respond to operational or reliability problems that arise in Real-Time, the NYISO may procure any Operating Reserve product at a quantity and/or price point different than those specified above. The NYISO shall post a notice of any such purchase as soon as reasonably possible and shall report on the reasons for such purchases at the next meeting of its Business Issues Committee. The NYISO shall also investigate whether it is necessary to modify the quantity and price points specified above to avoid future operational or reliability problems. The NYISO will consult with its Market Advisor when it conducts this investigation.

If the NYISO determines that it is necessary to modify the quantity and/or price points specified above in order to avoid future operational or reliability problems it may temporarily modify them for a period of up to ninety days. If circumstances reasonably allow, the NYISO will consult with its Market Advisor, the Business Issues Committee, the Commission, and the PSC before implementing any such modification. In all circumstances, the NYISO will consult with those entities as soon as reasonably possible after implementing a temporary modification.

Not later than 90 days after the implementation of the Operating Reserve Demand Curves, the NYISO, in consultation with its Market Advisor, shall conduct an initial interview of them in accordance with the NYISO Procedures. The scope of the review shall include, but not be limited to, an analysis of whether any Operating Reserve Demand Curve should be adjusted upward or downward in order to optimize the economic efficiency of any, or all, of the NYISO-Administered Markets. The NYISO and the Market Advisor shall perform additional quarterly reviews during the remainder of the first year that the Operating Reserve Demand Curves is in effect. After the first year, the NYISO and the Market Advisor shall perform periodic reviews, subject to the same scope requirement.

6.9 Self-Supply

Transactions may be entered into to provide for Self-Supply of Operating Reserves. Except as noted in the next paragraph, Customers seeking to Self-Supply Operating Reserves must place the Generator(s) supplying any one of the Operating Reserves under NYISO control. The Generator(s) must meet NYISO rules for acceptability. The amount that any such Customer will be charged for Operating Reserves will be reduced by the market value of the services provided by the specified Generator(s) as determined in the NYISO Services Tariff.

6.10 Operating Reserve Charge

Each Transmission Customer engaging in an Export and each LSE pays a monthly Operating Reserves charge under the NYISO OATT equal to the sum of the hourly charges for the month. The NYISO calculates and the LSE or Transmission Customer pays the hourly charge equal to the product of:

1. Cost to the NYISO of providing all Operating Reserves less any revenues from penalties collected during each hour

2. The ratio of:
 - a. The LSE's Load or the Transmission Customer's scheduled Export to
 - b. The sum of all Load in the NYCA and all scheduled Exports during that hour.

6.11 Failure to Provide Operating Reserve

There is no penalty for failing to perform under RTS, other than incurring an under-generation penalty. If the unit does not perform, the following will occur:

- RTD converted the reserve schedule to energy (i.e., the reserve schedule went to zero) and the unit would buy out of its day-ahead commitment.
- The unit would not receive any payment for energy produced.
- For more information, see [NYISO Accounting & Billing Manual](#).

6.12 Procedures for Notification of Poor Performers

The following procedures are for notifying suppliers in the event that they exhibit poor Operating Reserve performance.

In the initial LBMP implementation, these procedures will be performed at the end of each billing cycle.

NYISO Actions

The NYISO shall perform the following:

- 1) Notify the poor performing supplier via telephone or E-mail, upon determination by the NYISO that the supplier is exhibiting poor performance.
- 2) Notify the poor performing supplier that they are currently being penalized as described in the [NYISO Accounting & Billing Manual](#) and that persistent non-compliance in accordance with this procedure will result in additional penalties, and that consistent or continued poor performance will result in the provider being removed from the bidders list.

Reserve Provider Actions

The poor performer shall acknowledge the NYISO notification and report their expectation of the time they will be able to return to normal performance. The provider shall also describe the cause of their poor performance.

Attachment C – Regulation Performance Adjustment

Adjustment

Regulating units assist in maintaining both the scheduled interchange of energy with neighboring control areas and the scheduled frequency. The Automatic Generation Control (AGC) function monitors and controls net interchange and system frequency. The control of these quantities involves frequent signals to the suppliers of regulating service to adjust their output. Nominally, the AGC function requires an adjustment in the output of regulation service providers every six seconds. The effective control of interchange and frequency relies on the responsiveness of regulation service providers. That is, providers must react quickly and accurately to the control signals that would increase or decrease in output. The performance of regulation service providers is monitored and a payment factor is calculated for each provider. Good performers are paid for their regulation service at 100% of the market clearing price for regulation. Poor performers are paid only a portion of the market clearing price of regulation. That portion depends on the payment factor calculated for the provider – the worse (less responsive) the provider, the smaller the portion.

Symbol	Description
BP_{AGC30}^{+}	The largest of the six-second base points determined by AGC for a regulating unit over the past 30 seconds
BP_{AGC30}^{-}	The smallest of the six-second base points determined by AGC for a regulating unit over the past 30 seconds
$DAMCPreg_i$	Day-ahead clearing price of regulation service for the hour containing RTD interval “i”
$DARcap_i$	Amount of day-ahead regulation service scheduled from a supplier of regulation service for the hour containing RTD interval “i”
i	Index of an RTD interval.
K_{PI}^i	The regulation payment factor for RTD interval “i”
NCE_i	The negative control error of a regulating unit in RTD interval “i”
OG	Measured over-generation
PCE_i	The positive control error of a regulating unit in RTD interval “i”
PI_i	The regulation performance index in RTD interval “i”
PSF	The payment scaling factor
$RegPeriod_i$	Number of seconds during RTD interval “i” that the generating unit is supplying regulation service.
RR	Regulation ramp rate (MW/min) for a regulating unit
$Rsettlement_i$	Real-time portion of the settlement to a provider of regulation service for RTD interval “i”
$RTMCPreg_i$	Real-time clearing price of regulation service in RTD interval “i”
$RTRcap_i$	Amount of Real-Time regulation service scheduled in RTD interval “i” from a supplier of regulation service
s_i	Number of seconds in RTD interval “i”
UG	Measured under-generation
URM_i	The unit regulation margin in RTD interval “i”

Control Error

Both a positive and a negative control error are accumulated for each provider of regulation service in each RTD interval. The positive control error (PCE) is a measure of the provider's over-generation; the negative control error (NCE) is a measure of the provider's under-generation. Each 30 seconds the measured output of the regulation provider is compared to the largest and smallest of six-second base points generated during the previous 30 seconds. The provider is over-generating if measured output is greater than the largest of the six-second base points of the past 30 seconds. The provider is under-generating if measured output is less than the smallest of the six-second base points of the past 30 seconds. That is, every 30 seconds:

$$\begin{aligned} OG &= (MW_{\text{meas}} - BP_{\text{AGC30}}^+), \text{ but not less than zero} \\ UG &= (BP_{\text{AGC30}}^- - MW_{\text{meas}}), \text{ but not less than zero} \end{aligned}$$

Over- and under-generation is accumulated for each 30-second period in the RTD interval. That is:

$$\begin{aligned} PCE_i &= \sum_{\substack{\text{30-second periods} \\ \text{in the RTD interval}}} OG \\ NCE_i &= \sum_{\substack{\text{30-second periods} \\ \text{in the RTD interval}}} UG \end{aligned}$$

Unit Regulation Margin

The unit regulation margin is the amount that the regulation provider's output could change during an RTD interval. The unit regulation margin is calculated as:

$$URM_i = RR \times \left[\frac{s_i}{60} \right]$$

Regulation Performance Index

The regulation performance index tracks how well a regulation supplier responds to the control signals that are issued every six seconds. A regulation performance index is calculated for every RTD interval.

$$PI_i = URM_i - \left[\frac{PCE_i + NCE_i}{URM_i + 0.10} \right] \times \left[\frac{\text{RegPeriod}_i}{s_i} \right]$$

Regulation Payment Factor

A payment factor is calculated for each supplier of regulation service. The payment factor is used in the calculation of payments to the supplier. The payment factor is calculated as follows:

$$K_{PI}^i = \left[\frac{PI_i - PSF}{1 - PSF} \right]$$

Where:

PI is the Generator's performance index; and

PSF is the payment scaling factor, established pursuant to NYISO Procedures.

The PSF shall be set between 0 and the minimum performance index required for payment of Availability payments. The PSF is established to reflect the extent of NYISO compliance with the standards established by NERC, NPCC, or Good Utility Practice for Control Performance and System Security. The PSF is set initially at zero. Should the NYISO's compliance with these measures deteriorate, in a manner that can be improved if regulation performance improves, the PSF will be increased. Generators providing Regulation Service will be required to increase their performance index to obtain the same total Regulation Service payment as they received during periods of good NYISO performance, as measured by these standards.

Settlement for Regulation Service

The settlement of a regulation service provider for regulation service includes portions for day-ahead commitments to provide regulation service (if any) and balancing adjustments to account for deviations between day-ahead and Real-Time awards. The regulation payment factor is applied to the Real-Time portion of the settlement as shown below for an RTD interval. Total settlement for the day is simply the sum of the interval settlements for all intervals in the day.

$$R_{settlement_i} = (DARcap_i \times DAMCPreg_i) + \left[(RTRcap_i \times K_{PI}^i) - DARcap_i \right] \times RTMCPreg_i$$



Working to Perfect the Flow of Energy

PJM Manual 10:

Pre-Scheduling Operations

Revision: 22

Effective Date: May 15, 2007

Prepared by

System Operation Division

@PJM 2007

Manual 10:

Pre-Scheduling Operations

Table of Contents

Table of Contents	ii
Table of Exhibits	3
Approval	4
Current Revision	4
Introduction	5
ABOUT THIS MANUAL.....	5
<i>Intended Audience</i>	5
<i>References</i>	6
<i>What You Will Find In This Manual</i>	6
Section 1: Pre-Scheduling Overview	7
Section 2: Outage Reporting	11
OUTAGE REPORTING OVERVIEW	11
<i>Request Procedure</i>	12
<i>Rules & Regulations</i>	12
<i>Planned Outage Extension</i>	13
<i>Planned Outage Restrictions for Black Start Units</i>	13
<i>Maintenance General Information</i>	16
<i>Rules & Regulations</i>	16
<i>Maintenance Outage Extension</i>	16
UNPLANNED OUTAGES.....	17
Section 3: Reserve Objectives	18
<i>Operating Reserve</i>	18
<i>Objective Determination</i>	20
<i>Operating & Primary Reserve Objectives</i>	20
<i>Synchronized Reserve Requirement</i>	21
Section 4: Regulation Requirements	23
<i>Regulating Resource Eligibility</i>	23
<i>Regulating Resource Characteristics</i>	24
Section 5: Maintaining Market Information	25
<i>Hydro Resource Design Data</i>	26
Section 6: Winter Net Capability Test Exemption	31
PJM NET CAPABILITY VERIFICATION TESTS	31
WINTER NET CAPABILITY TEST EXEMPTION PROGRAM	31
<i>Pre-Scheduling Details</i>	32
<i>Scheduling Details</i>	32
<i>Scheduling Exceptions</i>	33
<i>Accounting Assumptions</i>	33



Completion of the Program	34
Attachment A: PJM Operating Reserve Objective Summary	35
Revision History	36

Table of Exhibits

EXHIBIT 1: PRE-SCHEDULING, SCHEDULING, AND DISPATCHING TIMELINE	8
EXHIBIT2: PJM ENERGY MARKET STRUCTURE	10
EXHIBIT 3: MAINTENANCE OUTAGE TIMELINE	15
EXHIBIT 4: GRAPHIC REPRESENTATION OF RESERVES	18
EXHIBIT 5: LIMIT RELATIONSHIP FOR REGULATION	24

Approval

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David Souder, Manager Operations Planning

Current Revision

Revision 22 (05/15/2007)

- Minor wordsmithing to align with NERC Functional Model
- Section 3:
 - Defined Contingency Reserves
 - Clarified Reserve Requirements, referencing PJM Emergency Operations Manual (M-13), Section 2 for additional details.
 - Clarified more conservative Mid-Atlantic Reserve Requirement based on historical transmission constraint limitations.

Section 3: Reserve Objectives

Welcome to the *Reserve Objectives* section of the **PJM Manual for Pre-Scheduling Operations**. In this section you will find the following information:

- A description of each type of Reserve (see “*Reserve Definitions*”).
- How Reserve Objectives are determined (see “*Objective Determination*”).
- A description of the PJM Seasonal Reserve Objectives (see “*PJM Seasonal Reserves*”).

Reserve Definition

Reserve represents the generating capability that is “standing by” ready for service in the event that something happens on the power system, such as the loss of a large generator. (Reference NERC Performance Standard BAL-002-0, Disturbance Control Performance, and PJM Manual 12, Attachment G). The severity of the event determines how quickly the reserves have to be picked up. Exhibit 4 illustrates how PJM classifies the different types of reserve.

Operating Reserve ($T \leq 30$ Minutes)			Reserve Beyond 30 Minutes
Primary/Contingency Reserve ($T \leq 10$ Minutes)		Secondary Reserve ($10 \text{ Min.} \leq 30 \text{ Minutes}$)	
Synchronized Reserve (Synchronized)	Non-Synchronized Reserve (Off-Line)		
T = Time Interval Following PJM Request			

Exhibit 4: Graphic Representation of Reserves

Operating Reserve

Operating Reserve is reserve capability including:

1. generating capability and/or equivalent generating capability scheduled to operate in excess of the forecast hourly integrated PJM RTO load that can be converted fully into energy within 30 minutes from the request of the PJM dispatcher or,
2. load that can be removed from the system in 30 minutes from the request of the PJM dispatcher.

Based on the time required to effect the reserve energy incremental contribution, Operating Reserve is subdivided into Primary Reserve and Secondary Reserve.

A. Primary or Contingency Reserve

NERC utilizes the term Contingency Reserves, which are on/off-line reserves available within 15 minutes. PJM criteria require response within 10 minutes. For the purposes of this manual, Primary and Contingency reserves are interchangeable. Primary Reserve is reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher.

Based on the operating status of the facility that is providing the reserve capability, Primary Reserve is subdivided into Synchronized Reserve and Non-Synchronized Reserve.

B. Synchronized Reserve

Synchronized Reserve is reserve capability that can be converted fully into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher and must be provided by equipment electrically synchronized to the system. Included as Synchronized Reserve are:

- i. the increase in the output energy level of a synchronized generator which can be attained within 10 minutes;
- ii. the reduction in load from a synchronized resource which can be attained in 10 minutes;
- iii. the load of a pumped hydro resource currently synchronized in the pumping mode and capable of being shut down within 10 minutes (provided that the PJM dispatcher had determined that the loss of the generating capability which the pumping would provide would not seriously affect future PJM RTO reliability); and
- iv. the maximum output energy level that could be attained within 10 minutes on a resource operating as a synchronous condenser, provided that:
 - (a) it has been determined that the loss of voltage control that would occur by reversing the synchronous condenser to generating mode would not seriously affect future PJM RTO reliability; and
 - (b) the interruption of the resource's synchronization is not required during transfer to the generating mode.

C. Non-Synchronized Reserve

Non-Synchronized Reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within 10 minutes of the request from the PJM dispatcher and is provided by equipment not electrically synchronized to the system. Included as Non-Synchronized Reserve are:

- i. the maximum output energy level of a resource which in the opinion of the Local Control Center dispatchers can be attained within 10 minutes from the PJM dispatcher's request to initiate the starting sequence; and
- ii. the reduction in load from a non-synchronized resource which can be attained in 10 minutes.

The resources that generally qualify in this category are currently shutdown run-of-river hydro, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle, diesels and interruptible demand resources.

D. Secondary Reserve

Secondary Reserve is reserve capability that can be fully converted into energy or load that can be removed from the system within a 10-to-30 minute interval following the request of the PJM dispatcher. Resources providing Secondary Reserve need not be electrically synchronized to the system.

Objective Determination

In the daily operation of the PJM RTO, the objective is to operate generating capability and/or equivalent generating capability as required to carry the load reliably and economically by providing reasonable protection against instantaneous load variations in excess of the hourly integrated values, load forecasting error, and loss of system capability due to generation equipment failure or malfunction and by providing reasonable capability for frequency regulation and area protection. The amount of reserve capability necessary to obtain this objective is established and reviewed periodically by PJM.

Reserve objectives are lower-limit reliability objectives. Synchronized Reserve, Non-Synchronized Reserve and Secondary Reserve have a priority sequence based on the level of reliability which each provides. Synchronized Reserve, being the most reliable, can also qualify for an objective which requires Non-Synchronized Reserve or Secondary Reserve. Likewise, Non-Synchronized Reserve can also qualify for an objective which requires Secondary Reserve. Since the system is to be operated in the most economical manner while satisfying each reserve objective, economics dictate the extent to which more reliable reserve excesses can be applied to subordinate reserve categories.

Capacity backed purchases from external systems do not qualify as PJM RTO reserve but may permit the attaining of reserve on participant-owned equipment. Non-capacity backed purchases cannot permit the attaining of reserve on participant-owned equipment.

Operating & Primary Reserve Objectives

The Operating and Primary Reserve objectives are calculated probabilistically. They differ due to their somewhat different treatment of the following factors:

- generator mix
- load level
- time of day
- day of week
- season of year
- load forecast uncertainty
- probability of equipment unplanned outage
- probability of equipment return
- probability of equipment failure to start
- exposure time interval (over which the interaction of these various factors is evaluated)

Synchronized Reserve Requirement

The Synchronized Reserve Requirement is determined at the discretion of PJM after careful review to ensure appropriate system reliability and maintain compliance with applicable NERC and Regional Reliability Organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. The Mid-Atlantic Reserve requirements are determined on a seasonal basis, recognizing potential deliverability issues.

E. PJM Seasonal Reserves

PJM Mid-Atlantic Seasonal Reserve Objectives are published periodically in a table format, as illustrated in Attachment A.

F. Operating Reserve Objectives

A table of Mid-Atlantic Operating Reserve objectives is calculated seasonally for various peak load levels and eight weekly periods. Reserve levels are probabilistically determined based on the season's historical load forecasting error and expected generation mix (including typical Planned and Unplanned Outages).

G. Primary Reserve Objective

An acceptable range of the Mid-Atlantic Primary Reserve objective is probabilistically determined based on the season's typical generation mix, ignoring Unplanned Outages, load forecasting error, and the other Operating Reserve objective contributing factors.

H. Synchronized Reserve Requirement Allocation Percentages

Synchronized Reserve Requirement Allocation Percentages are based on the real time load ratio share of each LSE to the PJM RTO.

Note: PJM Emergency Operations Manual (M-13), Section 2: Capacity Emergencies, Reserve Requirements Section provides a table which illustrates Reserve Requirements for the RFC and Dominion footprints of the PJM RTO. Additionally, Emergency Procedures are triggered on a more conservative reserve requirement for the Mid-Atlantic portion of the RTO footprint based on historic constraints which limit the ability to import energy from the west.

Section 4: Regulation Requirements

Welcome to the *Regulation Requirements* section of the **PJM Manual for Pre-Scheduling Operations**. In this section, you will find the following information:

- A description of Regulation (see “*PJM Regulation Service*”).
- A description of Regulating Resource Availability (see “*Regulating Resource Availability*”).
- A description of Regulating Resources (see “*Regulating Resource Characteristics*”).

PJM Regulation Service

The FERC Order 888 requires that the transmission providers within the PJM RTO provide the Ancillary Services for Regulation and frequency response. Since PJM is operating the PJM RTO, the Regulation and frequency response Ancillary Service is being coordinated by PJM.

NERC requires that the PJM RTO maintain regulating capability in order to match short-term deviations in system load. Regulation refers to the control action that is performed to correct for load changes that may cause the power system to operate above or below 60 Hz. To correct for these deviations from 60 Hz, PJM assigns the load changes to its faster responding resources, called regulating resources. By assigning regulation, PJM is better able to control the performance of the power system. Regulation is also referred to as regulation action or regulation response.

Regulation for the PJM RTO is supplied by Regulation Class from resources that are located within the metered electrical boundaries of the PJM RTO. Regulation is scheduled in the following ways:

- Self-Scheduled Resources
- PJM RTO Regulation Market

The amount of regulation capability that the PJM RTO is required to maintain and PJM Regulation Market process is discussed in the PJM Manual for **Scheduling Operations**.

Regulating Resource Eligibility

Regulating resources have the following characteristics:

- have Automatic Generation Control (AGC) capability
- be located within PJM Balancing Authority metered electrical boundaries
- have their outputs metered to the PJM OI

- be controlled by a Local Control Center or Market Operations Center
- meet the 75% (or applicable) regulation quality standard as described in the **PJM Manual for Balancing Operations (M-12)**

Regulating Resource Characteristics

The Capacity Resources assigned to meet the PJM Regulation Requirement must be capable of responding to the AR signal within five minutes and must increase or decrease their outputs at the Ramping Capability rates that are specified in the Offer Data that is submitted to the PJM OI.

A resource capable of automatic energy dispatch that is also providing Regulation reduces its energy dispatch range by the regulation assigned to the resource. This redefines the energy dispatch range of that resource. The resource's assigned regulation subtracted from its regulation maximum forms the upper limit of the new dispatch range, while the resource's regulation minimum plus its assigned regulation forms the lower limit of the new dispatch range. Exhibit 5 illustrates the limit relationship.

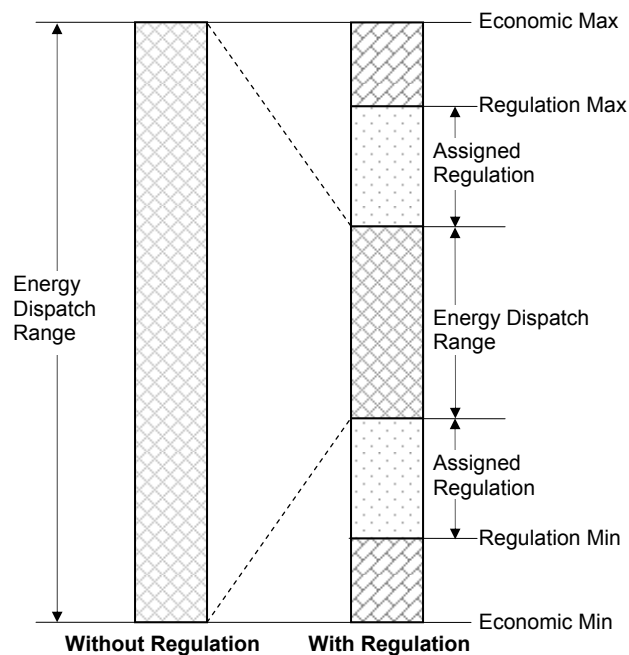


Exhibit 5: Limit Relationship for Regulation



Attachment A: PJM Operating Reserve Objective Summary

The current PJM Operating Reserve Objective Summary may be reviewed by clicking on the following link:

- [Current PJM Operating Reserve Objective Summary](#)

The PJM Operating Reserve Objectives for the last 3 seasons may be also be reviewed by clicking on the following link:

- [Previous PJM Operating Reserve Objective Summaries](#)



Working to Perfect the Flow of Energy

PJM Manual 11:

Scheduling Operations

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Prepared by

Forward Market Operations ©PJM 2007

Table of Contents

Table of Contents.....	ii
Table of Exhibits	v
Approval	6
Revision History.....	6
Introduction	7
ABOUT THIS MANUAL.....	7
<i>Intended Audience</i>	7
<i>References</i>	8
USING THIS MANUAL.....	8
<i>What You Will Find In This Manual</i>	8
Section 1: Overview of Scheduling Operations	10
PJM RESPONSIBILITIES	12
PJM MEMBER RESPONSIBILITIES	13
<i>Market Buyers</i>	13
<i>Market Sellers</i>	15
<i>Load Serving Entities</i>	15
<i>Curtailment Service Providers</i>	15
Section 2: Overview of the PJM Two-Settlement System	16
OVERVIEW OF TWO-SETTLEMENT.....	16
TWO-SETTLEMENT MARKET BUSINESS RULES	17
<i>Bidding & Operations Time Line:</i>	17
<i>Market Buyers</i>	18
<i>Market Sellers</i>	19
<i>Transmission Customers</i>	22
<i>Curtailment Service Providers</i>	22
<i>PJM Activities</i>	22
<i>Mechanical/Technical Rules</i>	24
<i>Modeling</i>	25
<i>Day-Ahead LMP Calculations</i>	25
<i>Settlements Data Requirements</i>	26
<i>Day-Ahead Settlement</i>	26
<i>Balancing Settlement</i>	28
<i>Maximum Emergency Generation in Day-Ahead Market</i>	28
<i>Minimum Capacity Emergency in Day-Ahead Market</i>	29
Section 3: Overview of the PJM Regulation Market.....	30
OVERVIEW OF THE PJM REGULATION MARKET	30
PJM REGULATION MARKET BUSINESS RULES.....	31
<i>Regulation Market Eligibility</i>	31
<i>Regulation Requirement Determination</i>	32
<i>Regulation Obligation Fulfillment</i>	32
<i>Regulation Offer Period</i>	33
<i>Regulation Market Clearing</i>	33
<i>Hydro Units</i>	34
<i>Regulation Market Operations</i>	35

Settlements	35
Section 4: Overview of the PJM Synchronized Reserve Market	37
OVERVIEW OF THE PJM SYNCHRONIZED RESERVE MARKET	37
PJM SYNCHRONIZED RESERVE MARKET BUSINESS RULES	38
<i>Synchronized Reserve Market Eligibility</i>	38
<i>Synchronized Reserve Requirement Determination</i>	39
<i>Synchronized Reserve Obligation Fulfillment</i>	40
<i>Synchronized Reserve Offer Period</i>	41
<i>Bilateral Synchronized Reserve Transactions</i>	41
<i>Synchronized Reserve Market Clearing</i>	42
<i>Hydro Units</i>	44
<i>Demand Resources</i>	44
<i>Synchronized Reserve Market Operations</i>	45
<i>Settlements</i>	45
<i>Verification</i>	48
<i>Non-Performance</i>	48
Section 5: Scheduling Philosophy and Tools	50
PJM PHILOSOPHY	50
SCHEDULING TOOLS	51
<i>Enhanced Energy Scheduler (EES)</i>	52
<i>PJM eSchedules</i>	52
<i>Load Forecasting</i>	52
<i>Markets Database System</i>	53
<i>Hydro Calculator</i>	56
<i>Two-Settlement Technical Software</i>	57
<i>Synchronized Reserve and Regulation Scheduling Software (SPREGO)</i>	60
Section 6: Scheduling Strategy and Method	62
FORECASTING PJM GENERATION REQUIREMENT	62
PJM REGULATION REQUIREMENTS	64
<i>Regulation Service</i>	66
PJM SYNCHRONIZED RESERVE REQUIREMENTS	67
<i>Synchronized Reserve Service</i>	69
PROCESSING MARKET INFORMATION	69
<i>PJM Member Load Forecasts</i>	70
<i>Reserve Service</i>	71
<i>Self-Scheduled Resources</i>	71
<i>Deviations from Day-Ahead Market for Pool Scheduled Resources</i>	71
<i>Credits for Cancellation of Pool Scheduled Resources</i>	72
<i>Resource Specific Data Requirements</i>	72
Section 7: External Transaction Scheduling	75
OVERVIEW OF EXTERNAL TRANSACTION SCHEDULING	75
EXTERNAL TRANSACTION SCHEDULING BUSINESS RULES	76
<i>PJM Contact Information</i>	76
<i>External Transaction Timing Requirements</i>	77
<i>General Information</i>	78
<i>Data Requirements</i>	79
<i>Ramp Limits</i>	79
<i>OASIS Business Rules</i>	80
<i>Entering Ramp Reservations</i>	83
<i>Entering Schedules</i>	84
<i>Entering Real-Time with Price Schedules</i>	84



<i>Entering Two-Settlement Schedules</i>	<i>85</i>
<i>Transaction Validations, Verification and Checkout</i>	<i>85</i>
Section 8: Posting OASIS Information	88
PJM OASIS	88
Section 9: Hourly Scheduling	90
HOURLY SCHEDULING ADJUSTMENTS	90
Section 10: Overview of the Demand Resource Participation	93
OVERVIEW OF DEMAND RESOURCE PARTICIPATION	93
DEMAND RESOURCE REGISTRATION REQUIREMENTS	94
<i>Curtailment Service Providers</i>	<i>94</i>
<i>PJM Activities.....</i>	<i>96</i>
DEMAND RESOURCE ENERGY MARKET PARTICIPATION	97
<i>Day-Ahead Operations</i>	<i>97</i>
<i>Real-Time Operations.....</i>	<i>98</i>
<i>Customer Baseline Load (CBL)</i>	<i>100</i>
<i>Settlements Data Requirements.....</i>	<i>102</i>
Attachment A: Interchange Energy Schedule Curtailment Order.....	104
CURTAILMENT OF TRANSMISSION OR RECALL OF ENERGY:	104
<i>Non-Firm over Secondary Points not willing to pay congestion charges</i>	<i>104</i>
<i>Non-Firm not willing to pay congestion charges (NF-NPC).....</i>	<i>104</i>
<i>Network Import not willing to pay congestion charges (Net-NPC).....</i>	<i>104</i>
<i>Spot Market Import (SPTIN)</i>	<i>104</i>
<i>Non-Firm over Secondary Points willing to pay congestion charges</i>	<i>105</i>
<i>Non-Firm willing to pay congestion charges (NF-WPC).....</i>	<i>105</i>
<i>Network Import willing to pay congestion charges (Net-WPC).....</i>	<i>105</i>
<i>Firm.....</i>	<i>105</i>
EXAMPLE OF RECALL OF ENERGY.....	106
<i>Firm.....</i>	<i>106</i>
<i>Curtailment of Capacity Backed Resources</i>	<i>106</i>

Table of Exhibits

EXHIBIT 1: SCHEDULING TIMELINE	11
EXHIBIT 2: LOAD FORECASTING PROCESS	53
EXHIBIT 3: SYNCHRONIZED RESERVE AND REGULATION MARKET DAILY TIMELINE.....	55
EXHIBIT 4: SYNCHRONIZED RESERVE AND REGULATION MARKET HOURLY TIMELINE	56
EXHIBIT 5: SETTLEMENT SUBSYSTEMS	58
EXHIBIT 6: DOWNLOAD DATA FROM MARKETS DATABASE.....	59
EXHIBIT 7: TWO-SETTLEMENT DATA FLOW.....	60
EXHIBIT 8: SYNCHRONIZED RESERVE AND REGULATION SUBSYSTEMS.....	61
EXHIBIT 9: REQUIREMENT VERSUS GENERATION SUPPLY.....	63
EXHIBIT 10: SYNCHRONIZED & REGULATION DATA FLOW	65
EXHIBIT 11: GENERATOR REGULATION SERVICE	67
EXHIBIT 12: SYNCHRONIZED & REGULATION DATA FLOW	69
EXHIBIT 13: PJM MEMBER ROLE IN PJM ENERGY MARKET.....	70
EXHIBIT 14: GENERATING RESOURCE SCHEDULING	71
EXHIBIT 15: CAPACITY AND NON-CAPACITY DATA REQUIREMENTS	73
EXHIBIT 16: EXAMPLE RAMP CALCULATION	80
EXHIBIT 17: ON-PEAK TRANSMISSION SERVICE OVER 16 HOUR PERIOD EXAMPLE.....	81
EXHIBIT 18 ON-PEAK TRANSMISSION SERVICE OVER 18 HOUR PERIOD EXAMPLE	81
EXHIBIT 19 OFF-PEAK MONDAY-FRIDAY TRANSMISSION SERVICE EXAMPLE	82
EXHIBIT 20: OFF-PEAK SATURDAY-SUNDAY TRANSMISSION SERVICE EXAMPLE.....	83
EXHIBIT 21: HOURLY SCHEDULING TIMELINE.....	91

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Mark Gravener, Manager

Forward Market Operations

Current Revision

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.

Section 3: Overview of the PJM Regulation Market

Welcome to the *Overview of the PJM Regulation Market* section of the PJM Manual for **Scheduling 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”).

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 eMarket 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 eMarket 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. 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.

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 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 over and above the RMCP and any un-recovered costs of resources called on by PJM to provide Regulation.

PJM Regulation Market Business Rules

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 Manuals.
 - 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.
- The following information must be supplied through the Two-Settlement Market User Interface (eMarket):
 - Resource Regulating Status (available, unavailable, self-scheduled)
 - Regulation Capability (above and below regulation midpoint, MW)
 - Regulation Offer Price (\$/MWHr). Offer prices will be capped at \$100/MWHr.
 - Regulation Maximum and Minimum values, considering any necessary offsets (MW)

The Regulation Offer Price 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. The remaining information may be submitted or changed up until sixty (60) minutes prior to 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.

Regulation Offer Prices submitted for generators in the Dominion and AEP control zones must reflect the marginal cost of providing the Regulation service from those generators, as defined in the PJM Cost Development Manual (M-15).

- The following changes in Resource Regulating Status may be made after the regulation market closes either through direct communication with the PJM Scheduling Coordinator or through the hourly updates screens of the Two-Settlement MUI:
 - 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 after the regulation market closes through direct communication with the PJM Scheduling Coordinator.
- Regulating capability may be decreased but not increased after the regulation market closes through direct communication with the PJM Scheduling Coordinator and through the hourly update screens of the Two-Settlement MUI.
 - Regulation Maximum may be decreased but not increased and Regulation Minimum may be increased but not decreased after the regulation market closes through the hourly update screens of the Two-Settlement MUI.
- 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 information may be changed for such resources, since none was considered in the calculation of RMCP.
- Resources that are self-scheduled for energy that 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.
- Demand Resources must complete initial training on Regulation and Synchronized Reserve Markets as detailed in Manual M-01 Control Center Requirements – Attachment C

Regulation Requirement Determination

- The total PJM Regulation Requirement for the PJM RTO is determined in whole MW for the entire day (0000 – 2359).
- The single Regulation Requirement for the PJM RTO is equal to 1% of the forecast peak 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.

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.

Regulation Offer Period

- Resource owners wishing to sell regulation service must supply a 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 Eligibility section.
- Regulation offers are locked as of 6:00 p.m. the day prior to operation. The Markets Database is unavailable for entry between 12 noon and 4:00 p.m. the day prior to operation while the commitment software is running. All resources listed as available for regulation with no offer price have their offer prices set to zero.
- Bilateral regulation transactions must be entered by the buyer and subsequently confirmed by the seller through the Two-Settlement MUI no later than 16:00 the day after the transaction starts. Bilateral transactions that have been entered and confirmed may not be changed; they must be deleted and re-entered. Deletion of a 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.

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.
- Resource merit order price (\$/MWhr) = Resource regulation offer + estimated resource opportunity cost per MWhr 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 forecasted energy schedule and 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. The approximate formula for this opportunity cost is:

$$|LMP - ED| * GENOFF, \text{ where:}$$

- a. LMP is the forecasted hourly LMP at the generator bus,

- b. ED is the price 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.
 - o This formula is somewhat simplistic. The actual calculation is an integration which 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 full amount of regulation, and the LMP
 - o 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.
 - o 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 start-up and no-load costs. Any unrecovered portion of these costs will be credited along with opportunity costs in the regulation settlement process.
- Non-capacity 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 on the user interface for public view.
- 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.

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:
 - o The formula is the same as above, except the ED value is an average of the LMP at the hydro unit bus for the appropriate on-peak or off-peak 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 in [a]) 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 Hourly Updates page of the Two-Settlement MUI.
- 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.

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.

Settlements

- 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.

- Regulation obligation is determined hourly for each LSE as follows:
 - for an LSE in the Mid-Atlantic Region, the ratio of the Mid-Atlantic Region regulation requirement over the PJM RTO requirement is multiplied times the total regulation assigned in the RTO, and then the real-time load ratio share within the Mid-Atlantic Region (adjusted for scheduled load responsibility) for the LSE is applied to the result.
 - for and LSE in the Western or Southern Region, the ratio of the of the sum of the Western and Southern Region regulation requirements over the PJM RTO requirement is multiplied times the total regulation assigned in the RTO, and then the real-time load ratio share within the combined Western and Southern Regions (adjusted for scheduled load responsibility) for the LSE is applied to the result.
- Regulation credits are awarded to resource owners that have either self-scheduled regulation or sold regulation into the market. Regulation credits for resource self-scheduled to provide regulation are equal to RMCP times the resource's self-scheduled regulating capability. Regulation credits for resources that offered regulation into the market and were selected to provide regulation are the higher of:
 - RMCP times the resource's assigned regulating capability, or
 - The resource's regulation bid times its assigned regulating capability plus opportunity cost incurred.
 - Demand Resources have zero opportunity cost.
- Opportunity cost is calculated as shown above in Market Clearing using actual integrated LMP 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.
- Non-capacity 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 **Scheduling 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*”).

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 eMarket 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 unit 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 which 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 resources selected by PJM 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 over and above the SRMCP and any unrecovered costs of resources called on by PJM to provide Synchronized Reserve.

PJM Synchronized Reserve Market Business Rules

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 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 Two-Settlement Market User Interface (eMarket):
 - 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, and must be greater than or equal to the economic maximum for the resource.
 - 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 (\$/MWhr). 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.
 - 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.

Synchronized Reserve Requirement Determination

Each Ancillary Service Area may have separate Synchronized Reserve Zones, but operated via the same market mechanism. 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) 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
- Dayton
- Duquesne
- CE

Southern 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.
 - 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.

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 Market Area synchronized reserve assigned. During hours when the Synchronized Reserve Market Clearing Price (SRMCP) is the same throughout the Market Area, an LSE's synchronized reserve obligation is equal to its load ratio share times the amount of synchronized reserve assigned for the Market Area. 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 reserve zone times the amount of synchronized reserve assigned in that reserve 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.

Synchronized Reserve Offer Period

- Synchronized Reserve offer prices for Tier 2 resources 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 can be submitted and/or updated up until 120 minutes prior to the operating hour, at which time PJM begins the process of estimating the Tier 1 Synchronized Reserve that will be available for the operating hour:
 - Synchronized Reserve Ramp Rate
 - Synchronized Reserve Maximum
- 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
- 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.

Bilateral Synchronized Reserve Transactions

- Bilateral synchronized reserve transactions must be entered by the buyer and subsequently confirmed by the seller through the Two-Settlement MUI no later than 16:00 the day after the transaction starts. Bilateral transactions that have been entered and confirmed may not be changed; they must be deleted and re-entered. Deletion of a 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 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.
- PJM will calculate and post the following indexes in order to provide an approximate value of synchronized reserve on which market participants may base prices for bilateral synchronized reserve transactions:
 - $(\text{Total hourly synchronized reserve cost}) / (\text{Total synchronized reserve assigned})$
 - $(\text{Total hourly synchronized reserve cost}) / (\text{Total Tier 2 assigned})$

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 estimates the amount of Tier 1 synchronized reserve that will be available on each resource. PJM posts this information on eMarket 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 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 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 assignments are made. 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 (\$/MWhr) = 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 eMarket by 1800 hours on the day preceding the operating day.
 - Estimated resource opportunity cost for condensing CTs is calculated as follows:

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

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

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

- 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 which 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 eMarket 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.
 - Non-capacity 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 all costs including start-up, no-load and minimum energy costs. Any unrecovered portions of these costs are credited as part of the synchronized reserve settlement process described below.
 - 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 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.
 - The hourly Tier 2 clearing prices are posted on the eMarket 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.

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 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’, in rule #1d, third bullet, except the ED value is the average value of the LMP at the hydro unit bus for the on-peak 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. 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.
 - 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.

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 end of the 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.

- Demand Resources must complete initial training on Regulation and Synchronized Reserve Markets as detailed in Manual M-01 Control Center Requirements – Attachment C

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.

Settlements

- 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.
- Synchronized Reserve obligation is determined hourly for each participant by applying the real-time load ratio share (adjusted for scheduled load responsibility) to the total synchronized assigned in the Synchronized Reserve Zone for that hour (considering locational constraints as noted above), and then adding bilateral sales and subtracting bilateral purchases. Synchronized Reserve charges are then determined for both the amount of Tier 1 applied to each participant's obligation and the amount of Tier 2 each participant purchased from the market.
- Tier 1 charges for each participant are equal to the percentage share of the overall Tier 1 credits according to the amount of Tier 1 applied to their obligation. The amount of Tier 1 applied to each participant's obligation is equal to the amount of Tier 1 estimated prior to the operating hour as part of the market clearing process on that participant's own resources up to the amount of obligation, plus the remaining load ratio share of any excess Tier 1 estimated on the resources of generation owners in excess of their individual obligations. Note that Tier 1 charges will only exist if a synchronized reserve event occurs within a given hour.
- Tier 2 synchronized reserve charges for each participant are equal to:
 - The appropriate hourly Tier 2 clearing price times the MW of Tier 2 self-scheduled toward the participant's obligation plus that which is purchased from the market plus;

- The participant's share of any un-recovered costs incurred by assigned Tier 2 resources over and above the Tier 2 clearing price plus;
- The participant's share of any un-recovered costs incurred by those resources PJM committed for the sole purpose of providing synchronized reserve plus;
- The participant's share of the costs of those Tier 2 resources assigned in addition to that which was estimated prior to a given hour.

The appropriate hourly Tier 2 clearing price for each LSE is the clearing price for the sub-zone or Synchronized Reserve Zone which the LSE's load is located. Loads located in a reserve zone will pay that sub-zone's SRMCP. Loads not located in a sub-zone will pay the corresponding area Synchronized Reserve Zone SRMCP (i.e. RFC or Southern).

The costs listed in items b), c) and d) above are allocated as follows:

Un-recovered costs incurred by Tier 2 resources assigned by PJM either during the Tier 2 clearing process or during the operating hour due to conditions other than a reduction in available Tier 1 Synchronized Reserve are allocated based on each participant's pro-rata share of Tier 2 synchronized reserve purchased from the market.

The cost of Tier 2 resources assigned by PJM during the operating hour in addition to that which resulted from the Tier 2 clearing process due to reduced availability of Tier 1 Synchronized Reserve are allocated to those entities for which less Tier 1 was available during the hour than was estimated prior to the hour, in proportion to the reduction in Tier 1 availability.

- During hours when the Tier 2 clearing price is the same for an entire Synchronized Reserve Zone, the Tier 2 each participant purchases from the market is defined as that participant's obligation less the Tier 1 applied, less Tier 2 self-scheduled, plus bilateral sales, minus bilateral purchases. During hours when the Tier 2 clearing price varies across a Synchronized Reserve Zone, the Tier 2 each participant purchases from the market is defined as that participant's load ratio share of the synchronized reserve required in the appropriate Synchronized Reserve Zone or sub-zone less the Tier 1 applied, less Tier 2 self-scheduled, plus bilateral sales, minus bilateral purchases.
- Tier 1 synchronized reserve credits are awarded to all generation owners whose resources increased output in response to a synchronized reserve event (with the exception of those resources that were assigned Tier 2 synchronized reserve.) These credits are equal to the integrated increase in MW output from each generator over the length of the event, times the synchronized reserve energy premium less the hourly integrated LMP. The amount of the increase in output is defined as stated in the Verification section below. The synchronized reserve energy premium is defined as the average of the 5-minute LMPs calculated during the synchronized reserve event plus \$50/MWh. In cases where a synchronized reserve event spans two or more hours, the response from each resource will be integrated according to the length of response in each hour for the purpose of calculating the Tier 1 credit.
- 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 according to the following formula:

$$(T1P - LMP) \times \left\{ \left[\max(0, \text{integrated}(\text{Output} - \min(\text{EcoMax}, \text{RegHighLimit}))) \right] + \left[\max\left(0, \left(\text{integrated} \left\{ \min(\text{EcoMax}, \text{RegHighLimit}, \text{Output}) - \text{Initial Output} - (2 \times \text{RegMW}) \right\} \right) \right) \right] \right\}, \quad \text{where :}$$

- T1P is the Tier 1 synchronized reserve energy premium (average of the five-minute LMPs during the synchronized reserve event plus \$50)
- LMP is the hourly integrated LMP for the hour in which the synchronized reserve event occurs
- 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 offered synchronized reserve into the market and were selected 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.

- For all resources dispatched as a result of a Synchronized Reserve event, an additional daily make-whole evaluation is performed to ensure that a resource's total cost to provide the Synchronized Reserve service (including, but not limited to, hourly offer costs, energy use costs and startup costs for generation, and shutdown costs for demand resources) is greater less than or equal to the resource's daily synchronized reserve credits. If the daily costs exceed the daily credits, an additional opportunity cost payment is made to the resource for the difference. The daily costs are further defined in the Cost Development Task Force Manual (CDTF).
- 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 are therefore exempt from deviations for the purpose of accumulating operating reserves charges, for the MW response associated with the Tier 2 assignment, for the hours during which the Tier 2 assignment is effective.

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.

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.

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 website 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 PM 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.

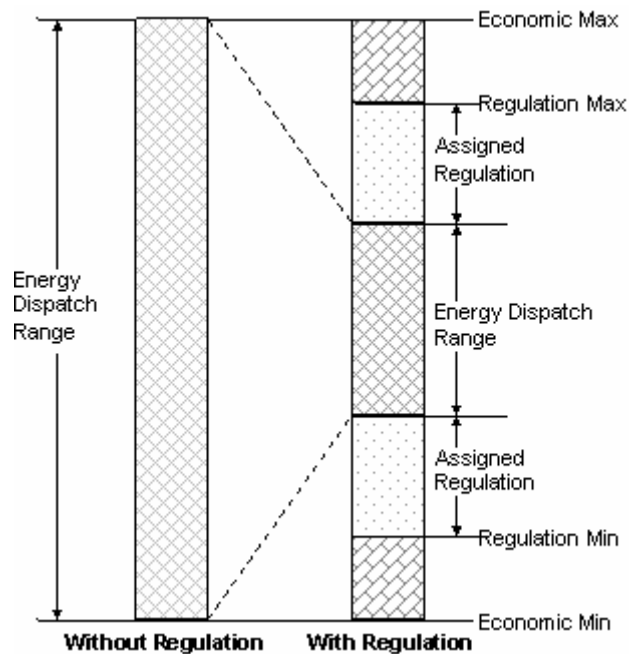


Exhibit 11: Generator Regulation Service

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 [Dispatching Operations \(M-12\)](#) for a description of the Regulation allocation process during the course of system operation.

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 PJM synchronized reserve capability equal to the control 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). Exhibit 10 summarizes this information.

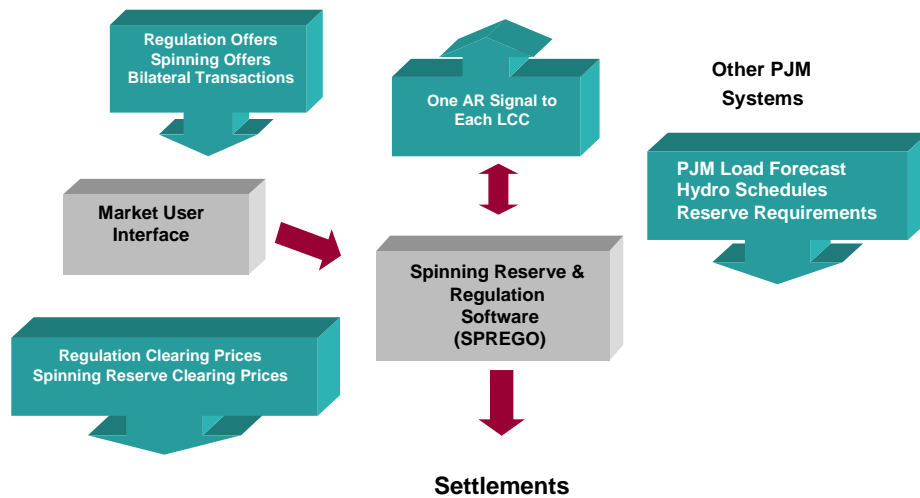


Exhibit 12: Synchronized & Regulation Data Flow

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

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 website 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 pm 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.

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



Working to Perfect the Flow of Energy

PJM Manual 12: Balancing Operations

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Prepared by Mike Bryson
Dispatching

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PJM Manual 12:

Balancing Operations

Table of Contents

Table of Contents.....	ii
Table of Exhibits	v
Approval.....	1
Current Revision	1
Introduction	2
ABOUT PJM MANUALS.....	2
ABOUT THIS MANUAL.....	2
<i>Intended Audiences</i>	<i>2</i>
<i>References.....</i>	<i>3</i>
USING THIS MANUAL	3
<i>What You Will Find In This Manual.....</i>	<i>3</i>
Section 1: Overview	4
SCOPE AND PURPOSE OF DISPATCHING	4
PJM RESPONSIBILITIES	6
<i>PJM Communications</i>	<i>6</i>
PJM MEMBER RESPONSIBILITIES	7
<i>Market Buyers</i>	<i>7</i>
<i>Market Sellers</i>	<i>8</i>
<i>Load Serving Entities</i>	<i>8</i>
Section 2: Dispatching Tools.....	9
CONTROL CENTER TOOLS	9
<i>EMS Applications.....</i>	<i>9</i>
<i>PC Applications.....</i>	<i>9</i>
<i>Ancillary Tools.....</i>	<i>11</i>
Section 3: System Control	12
ADJUSTING PJM CONTROL AREA-SCHEDULED RESOURCES.....	12
<i>PJM Area Control Error.....</i>	<i>12</i>
<i>PJM Control Implementation.....</i>	<i>16</i>
<i>PJM Member Control Implementation</i>	<i>19</i>
TIME ERROR	21
<i>Time Error Correction Notification.....</i>	<i>21</i>
EXTERNAL TRANSACTIONS SCHEDULING	22
<i>Overview of External Transaction Scheduling</i>	<i>22</i>
EXTERNAL TRANSACTION SCHEDULING BUSINESS RULES	23
<i>PJM Contact Information</i>	<i>23</i>
<i>External Transaction Timing Requirements.....</i>	<i>23</i>
<i>General Information</i>	<i>24</i>
<i>Data Requirements</i>	<i>25</i>
<i>Ramp Limits</i>	<i>25</i>
<i>OASIS Business Rules</i>	<i>26</i>
<i>Entering Ramp Reservations.....</i>	<i>29</i>
<i>Entering Schedules.....</i>	<i>29</i>

<i>Entering Real-Time with Price Schedules</i>	30
<i>Entering Two-Settlement Schedules</i>	30
<i>Transaction Validations, Verification and Checkout</i>	31
INADVERTENT INTERCHANGE	32
<i>Correcting for Accumulation of Inadvertent Interchange</i>	33
<i>Measurements and Compliance</i>	34
Section 4: Providing Ancillary Services	35
RESERVES	35
<i>Monitoring Reserves</i>	35
<i>Loading Reserves</i>	36
SHARED RESERVES	37
<i>Payback</i>	39
<i>Restoring Reserves</i>	39
VACAR RESERVE SHARING	40
REGULATION	40
<i>PJM RTO Regulation Market Obligations</i>	40
<i>Regulation Signals</i>	42
<i>Determining Regulation Assignment</i>	43
<i>Dispatching Regulation</i>	44
QUALIFYING REGULATING RESOURCES	46
<i>Regulation Test</i>	46
<i>Certifying Regulating Resource</i>	49
<i>Certifying Multiple Combustion Turbines or Hydro Units at a Single Site</i>	49
<i>Increasing Regulation Capability on a Resource</i>	49
BLACK START SERVICE	50
<i>Restoration Assumptions</i>	51
<i>Jurisdiction</i>	51
<i>Definitions</i>	51
<i>Objectives of Determining Black Start Criticality</i>	51
<i>Assumptions</i>	52
<i>Minimum Critical Unit Requirements</i>	52
<i>Critical Unit Restrictions for Eligible Compensation under the PJM Black Start Service</i>	52
<i>Exceptions</i>	52
<i>Product Description</i>	53
<i>Generator Owner's Commitment</i>	53
<i>Performance Standards</i>	54
<i>PJM Obligations</i>	54
<i>Testing</i>	55
<i>Testing and Training Standards and Records</i>	55
<i>Non-performance</i>	56
Section 5: Transmission Facility Control	58
CORRECTIVE CONTROL STRATEGIES	58
REACTIVE LIMITATION CONTROL	60
VOLTAGE CONTROL	61
<i>Action in a Low-Voltage Situation</i>	62
<i>500 kV System Voltage Below 500 kV</i>	62
<i>Action in a High-Voltage Situation</i>	62
THERMAL OVERLOADED TRANSMISSION	63
<i>Transaction Curtailment</i>	63
<i>Generation Redispatch</i>	64
<i>Operating Mode Change Procedure</i>	65
Attachment A: PJM Instantaneous Reserve Check (IRC)	66



IRC - DEFINITIONS OF TERMS / CALCULATIONS	66
Attachment B: Transmission Constraint Control Guidelines	71
NON-COST MEASURES	71
GENERATION REDISPATCH.....	71
Attachment C: PJM Black Start Test Report Form	73
Attachment D: PJM Auto Load Reject Test Report Form.....	75
Attachment E: PJM Black Start Formulaic Cost Data Form.....	77
Attachment F: PJM Black Start Actual Cost Data Form	78
Attachment G: Disturbance Control Performance/Standard	80
Attachment H: PJM REPORTING OF NERC BAL Standard.....	82
PJM Manual 12 Revision History	93

Table of Exhibits

EXHIBIT 1: DISPATCHING TIMELINE	5
EXHIBIT 2: DISPATCH OPERATIONS OVERVIEW	7
EXHIBIT 3: CALCULATION OF PJM ACE	13
EXHIBIT 4: PJM REGULATION SIGNALS	17
EXHIBIT 5: CALCULATION OF DISPATCH PRICE AND MW SIGNALS	18
EXHIBIT 6: RESOURCE DISPATCHING	19
EXHIBIT 7: PJM MEMBER INTERFACE	20
EXHIBIT 8: EXAMPLE RAMP CALCULATION.....	26
EXHIBIT 9: ON-PEAK TRANSMISSION SERVICE OVER 16 HOUR PERIOD EXAMPLE	27
EXHIBIT 10: ON-PEAK TRANSMISSION SERVICE OVER 18 HOUR PERIOD EXAMPLE	27
EXHIBIT 11: OFF-PEAK MONDAY-FRIDAY TRANSMISSION SERVICE EXAMPLE	28
EXHIBIT 12: OFF-PEAK SATURDAY-SUNDAY TRANSMISSION SERVICE EXAMPLE.....	28
EXHIBIT 13: LIMIT RELATIONSHIP FOR REGULATION.....	41
EXHIBIT 14: AREA REGULATION ASSIGNMENT	44
EXHIBIT 15: REGULATION TEST PATTERN	47
EXHIBIT 16: CORRECTIVE CONTROL STRATEGIES.....	59
EXHIBIT 17: POWER SYSTEM LIMITS	60
EXHIBIT 18: PJM INSTANTANEOUS RESERVE CHECK TERMS & RELATIONSHIPS	66
EXHIBIT 19: DEFINITIONS OF PJM INSTANTANEOUS RESERVE CHECK TERMS	68
EXHIBIT 20: SAMPLE PJM INSTANTANEOUS RESERVE CHECK FORM.....	69

Section 4: Providing Ancillary Services

Welcome to the *Providing Ancillary Services* section of the **PJM Manual for Balancing Operations**. In this section you will find the following information:

- How PJM monitors and restores reserves (see “Reserves”).
- How PJM determines and assigns Regulation (see “Regulation”).
- How a generating resource is tested and qualified for Regulation service (see “Qualifying Regulating Resources”).
- How PJM ensures and monitors Black Start Service (see “Black Start Service”).

Reserves

Reserves are the additional capacity above the expected load. Scheduling excess capacity protects the power system against the uncertain occurrence of future operating events, including the loss of capacity or load forecasting errors.

Monitoring Reserves

PJM is responsible for monitoring and adjusting the reserves to ensure compliance with RFC-OPR-001, “Operating Reserves” and NERC BAL standards for the PJM Control Area. On a daily basis the PJM dispatcher performs an Instantaneous Reserve Check (IRC) prior to each peak or more often as system conditions require to determine if adequate reserves exist to meet the PJM Reserve Requirements. An IRC may be taken more frequently if system conditions dictate. When the PJM Generation dispatcher requests an IRC, member dispatchers report the information via eDART. If eDART is unavailable, member dispatchers report the information directly to the PJM Generation dispatcher. Attachment A presents and describes the PJM IRC report.

An IRC provides PJM dispatcher with an indication of the actual reserves that are available at that point in time. By conducting an IRC at strategic points during the day, PJM dispatcher establishes benchmarks between which the actual reserve can be estimated. Since system conditions can change very rapidly, the IRC is only an indication of the actual reported reserves at that point in time. PJM dispatcher uses the results of the IRC to determine if reserve shortages exist and what, if any, Emergency procedures should be declared to supplement the electronic reporting of reserves through the EMS systems.

When the PJM Net Tie Deviation indicates undergeneration, the Synchronized Reserve total is adjusted downward by the amount of the Net Tie Deviation to reflect the PJM Control Area’s generation deficiency. Conversely, when the PJM Net Tie Deviation indicates overgeneration, the Synchronized Reserve total is adjusted upward by the amount of the Net Tie Deviation to reflect the PJM Control Area’s generation excess. Therefore, when possible PJM dispatcher requests an IRC when the ACE and Net Tie Deviation is close to zero MW.

PJM Actions:

- **Step One** - Using the PJM ALL-CALL, PJM dispatcher requests an IRC.
- **Step Two** - Upon receipt of all Generation Owner reports, PJM dispatcher determines the following values:

- PJM Operating Reserve
- Adjusted Primary Reserve versus Primary Reserve Requirement.
- Adjusted Synchronized Reserve versus Synchronized Reserve Requirement.
- Unaccounted for capacity
- Area Synchronized Reserve levels
- **Step Three** - PJM dispatcher compares the values calculated in Step (2) to the corresponding objectives and then determines whether reserve deficiencies exist.
- **Step Four** - Using the PJM eDART, PJM dispatcher reports the results of the IRC to the Generation Owners/Transmission Owners.

PJM Member Actions:

- **Step One** - The Generation Owner dispatchers promptly report the following values to PJM via eDART. If eDART is unavailable, the values are reported directly to PJM dispatcher via telephone:
 - Normal Regulating Reserve
 - Spinning Reserve Non-Regulating
 - Normal Regulating Reserve
 - Spinning Reserve Non-Regulating
 - Spinning Reserve Regulating
 - Quick Start Reserves
 - Secondary Reserve
 - Operating Reserve
 - Scheduled capability that is more than 30 minutes away
 - Capacity reductions that are not known to PJM dispatcher

See [Attachment A](#) for reserve calculations and IRC reporting requirements.

Loading Reserves

During disturbance conditions (i.e., loss of generation and/or transmission resources), synchronized reserve and, to the extent necessary, Non-Synchronized Reserves are used to recover the ACE so that tie line schedules are maintained. Depending on system conditions, the manual methods may be used to accomplish this recovery.

- **Manual Method** — Includes raising the Lambda signal manually and committing additional equipment.

PJM Actions:

- PJM dispatcher determines the approximate amount and location of lost generation, and the amount of Synchronized Reserve that must be loaded to:

- Correct for the sudden loss of generation located within the PJM Control Area (as indicated by the PJM Control Area's ACE and system frequency deviations)
- Return interchange transfers or other thermal or reactive limitations to within the appropriate limits
- PJM dispatcher requests the Resource Owner, via the PJM ALL-CALL, to load a percentage (25%, 50%, 75%, or 100%) of the Synchronized Reserve (typically 100%) in the appropriate control zone(s). PJM has several Synchronized Reserve markets (MAAC area, ECAR area, MAIN area, and VACAR area). The dispatchers will select the most effective response respecting the requirements of the regional reserve sharing programs in which PJM is a participant.
 - If specific equipment is excluded from the request, PJM dispatcher calls the appropriate Resource Owner immediately following the PJM ALL-CALL message.
 - If transmission limits exist or may be caused by loading Synchronized Reserve and Non-Synchronized Reserve in certain geographic areas or control zones, PJM dispatcher specifies the areas or control zones that are to be included in the request for Synchronized Reserve.
 - If PJM dispatcher anticipates that loading of Synchronized Reserve may continue for longer than ten minutes, PJM dispatcher includes this statement in the PJM ALL-CALL message.
 - PJM Dispatcher contacts external systems to implement Shared Reserves (as required).
 - PJM dispatcher also requests the loading of an appropriate amount of non-synchronized reserve (as required).
 - If PJM dispatcher determines that the Synchronized Reserve that is being loaded is not sufficient to recover the system from a facility malfunction or failure, PJM dispatcher requests synchronized Secondary Reserve to be loaded (as required).
- As the Resource Owner dispatchers load the reserves, PJM dispatcher evaluates the effect. PJM dispatcher surveys the resources loaded and determines generation that is needed to remain loaded and the replacement resources that can be returned to normal status so that the PJM Control Area load can be economically carried at a new price level.
- PJM dispatcher cancels the requests, as appropriate.

PJM Members Actions:

- The resource owners, without regard to price and as quickly as possible, load the requested percentage of Synchronized Reserve and Non-Synchronized Reserve. PJM Members continue to load resources until directed by PJM dispatcher to discontinue.
- Upon cancellation, the generation owner dispatchers unload the Synchronized and Non-Synchronized Reserve, as directed by PJM dispatcher.

Shared Reserves

Shared Reserve Activation is a procedure between the Northeast Power Coordinating Council (NPCC) and the PJM Mid-Atlantic Control Zone (former MAAC region member companies) to jointly activate a portion of their ten-minute reserve following any of the following situations:

- Generation or energy purchase contingencies equal to or greater than 500 MW (300 MW for Maritimes) occur under conditions where activation assists in reducing a sustained load/generation mismatch
- Two or more resource losses below 500 MW (300 MW for Maritimes) within 1 hour of each other.
- Periods of significant mismatch of load and generation

The participating systems in NPCC shared reserves are the ISO New England (ISO NE), the New York Independent System Operator (NYISO), PJM East Control Zone, Maritimes, New Brunswick and Independent Electricity Market Operator (IESO formerly IMO of Ontario). The objective is to provide faster relief of the initial stress on the interconnected transmission system. The NPCC Operating Reserve Policy and the Operating Reserve Policies of all NPCC areas and of the PJM Mid-Atlantic Control Zone are not changed by any of the provisions of this plan.

The NYISO acts as the plan coordinator.

PJM Actions:

If the loss of generation/purchase is located in the NPCC:

- The NYISO supervising dispatcher assigns the PJM Mid-Atlantic Control Zone a share of reserve pick-up. NYISO indicates the amount of participation.
- PJM dispatcher manually adjusts regulation, loads generation, or Synchronized Reserve in selected areas or across the entire PJM Mid-Atlantic Control Zone based on transfer limitations. This assistance is implemented at a zero time ramp rate immediately following allocation notification. Response by assisting control areas shall respond as quickly as possible, assuming the same obligation as if the contingency occurred within the control area. This should be implemented via manually adjusting regulation if possible.
- PJM dispatcher notifies the NYISO supervising dispatcher that PJM Mid-Atlantic Control Zone's reserve pick-up is completed.
- When the contingent system satisfies its ACE requirements, they notify the NYISO supervising dispatcher, who requests all participants to cancel their shared reserve allocations (normally ten minutes, but no longer than 30 minutes) when the generator loss is replaced. The assistance provided by the PJM Mid-Atlantic Control Zone is ramped out at a ten-minute ramp rate.
- When the PJM Mid-Atlantic Control Zone completes its reserve pick-up, PJM dispatcher notifies the Local Control Centers to cancel Synchronized Reserve loading.

If the loss of generation/purchase is located in the PJM Mid-Atlantic Control Zone:

- PJM dispatcher activates 100% Synchronized Reserves and notifies the NYISO supervising dispatcher of generation loss, and includes any special requests. For example, for the loss of a large eastern unit, PJM dispatcher may request IMO not to participate.

- The NYISO supervising dispatcher activates shared reserves and notifies PJM dispatcher, via conference call, of the ten-minute reserve amount that NPCC members contribute.
- PJM dispatcher terminates shared reserves (normally ten minutes, but no longer than 30 minutes) when the generation loss is replaced.

Payback

Currently, payback mwhs are not required for NPCC Shared Reserve Events.

PJM Member Actions:

None.

Restoring Reserves

By continuously monitoring reserves, PJM dispatcher ensures that reserve levels are maintained in accordance with NERC BAL Standards. During normal operation, PJM dispatcher loads the system based on economy while monitoring the available reserves. If, however, based on the best judgment of PJM dispatcher after evaluating the results of the IRC, reserve deficiencies exist on the system, the following actions are taken, dependent on the deficiency:

- Synchronized Reserve Deficiency — Normally, restoration of Synchronized Reserve is accomplished by condensing CTs, notifying interruptible load resources, or loading Non-Synchronized Reserve or Secondary Reserve to a minimum level to provide sufficient Synchronized Reserve or to the economic energy level to allow equipment (i.e., steam units) to back down to provide sufficient Synchronized Reserve.
- Primary Reserve Deficiency — When PJM dispatcher is assured that the Synchronized Reserve objective is covered, PJM dispatcher attempts to eliminate any Primary Reserve deficiency. Restoration is accomplished by any combination of the following actions:
 - loading Secondary Reserve to Primary Reserve status or providing additional Primary Reserve on other equipment
 - bringing additional equipment which is available but not scheduled to operate into the Primary Reserve status

That portion of the Primary Reserve deficiency that is due to an adjustment to the internal PJM Primary Reserve as a result of a net non-capacity interchange scheduled into PJM can be tolerated provided system reliability is not degraded. On these occasions, PJM dispatcher ensures that sufficient shutdown CT and/or hydro capability are readily available to cover the amount of the deficiency.

- Operating Reserve Deficiency — When PJM dispatcher is assured that both the Synchronized and Primary Reserve objectives are covered, PJM dispatcher attempts to eliminate any deficiency in Operating Reserve. Sufficient reserve is maintained for coverage of load-forecast uncertainty and probable additional failure or malfunction of generating equipment. The decision of whether to replenish Operating Reserve is based on PJM dispatcher's best judgment. PJM dispatcher may choose to replenish all, some, or none of the Operating Reserve during the operating day.

VACAR Reserve Sharing

PJM, on behalf of Dominion-Virginia Power, participates in the VACAR reserve sharing group, which consists of Dominion-Virginia Power, Duke Power, South Carolina Electric and Gas, Progress Energy-Carolinas, and South Carolina Public Service Authority. The purpose of the agreement is to share reserves to enhance reliability and to decrease the cost of maintaining reserves for each system.

Upon the telephone request of a member, the responding member will provide reserve energy for a period of up to 12 hours to support the needs of the requesting member.

PJM Actions:

Respond to requests for assistance due to a contingency event, as requested by another member, by scheduling delivery of VACAR reserve energy to the requesting member for delivery at the border between PJM and the CPL control area.

Request the scheduling of VACAR reserve energy from other VACAR members if needed. Energy will be received at the CPL control area border with PJM.

Dominion-Virginia Power Actions:

Performs billing and provide compensation, as applicable, for reserve energy received by PJM called for on behalf of Dominion or provided by PJM on behalf of Dominion to another VACAR member.

Regulation

The PJM RTO is a single Control Area consisting of multiple Control Zones. Regulation for each Control Zone is supplied from resources that are located within that zone. Resource owners providing Regulation are required to comply with standards and requirements of Regulation capability and dispatch, as described in this section.

PJM RTO Regulation Market Obligations

The Regulation Requirement for the PJM RTO is 1.0% of the forecast peak load for the entire day. There is no distinction between On-Peak Periods and Off-Peak Periods. The resources assigned to meet this requirement must be capable of responding to the AR signal immediately, achieve their bid capability within five minutes and must increase or decrease their outputs at the ramping rates that are specified in the data that is submitted to PJM.

The PJM RTO requires that the Regulation range of a resource is at least twice the amount of Regulation assigned. A resource capable of automatic energy dispatch that is also providing Regulation reduces its energy dispatch range by the regulation assigned to the resource. This redefines the energy dispatch range of that resource. (The resource's assigned regulation subtracted from its regulation maximum forms the upper limit of the new dispatch range, while the resource's regulation minimum plus its assigned regulation forms the lower limit of the new dispatch range.) Exhibit 8 illustrates the limit relationship

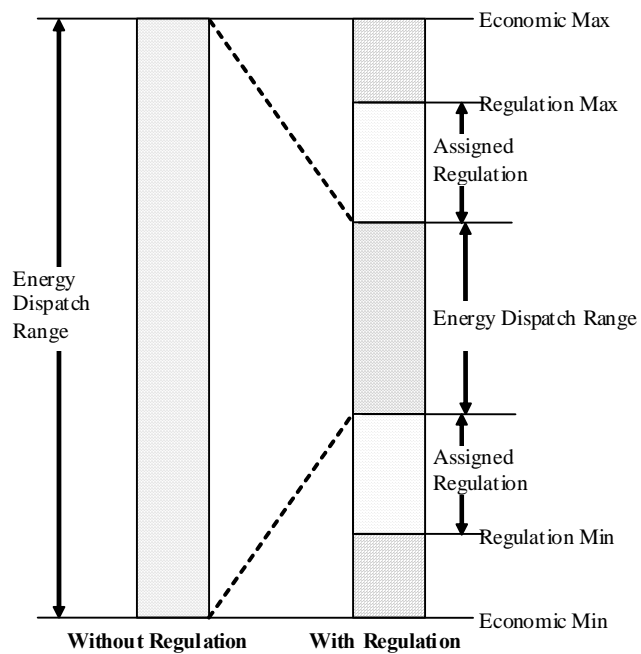


Exhibit 13: Limit Relationship for Regulation

Resource owners wishing to provide Regulation in the PJM control area are required to submit the following data via eMKT no later than 6:00 p.m. day-ahead:

- **Offer MW** — The maximum MW amount of regulation that the resource is willing to provide for the next day. This value is limited by the resource's qualified capability. Offer MW may be adjusted hourly throughout the operating day giving 60 minutes notice before the operating hour.
- **Offer Price** — The price in \$/MWH at which the owner is willing to provide Regulation from the associated resource. This value can not be changed after 6:00pm day-ahead.
- **Available Status** — Indication of whether the resource is available, unavailable or self-scheduled for Regulation. Available Status may be adjusted hourly throughout the operating day giving 60 minutes notice before the operating hour.
- **Regulation Max MW**— The maximum MW value the resource can attain while providing Regulation. Regulation Max MW may be adjusted hourly throughout the operating day giving 60 minutes notice before the operating hour.
- **Regulation Min MW** — The minimum MW value the resource can attain while providing Regulation. Regulation Min MW may be adjusted hourly throughout the operating day giving 60 minutes notice before the operating hour.
- **Min MW** — The minimum amount of regulation the resource is physically capable of providing for an hour. This number must be less than or equal to the Offer MW. This value can not be changed after 6:00pm day-ahead.

Regulation Signals

Resource owners will receive from PJM:

- **AReg** – Assigned Regulation. This is the assigned hourly regulation quantity (MW) that is cleared from the regulation market system. It is assigned for each individual resource that is qualified to regulate in the PJM market. This value, although typically static for the hour, will be sent on a 10 second scan rate.
- **RegA** – Real-time instantaneous resource owner fleet regulation signal (+/- MW). This signal is used to move regulating resources in the owner's fleet within the fleet capability (+/- TReg). This value will be sent on a 2 second scan rate.

Resource owners will send to PJM:

- **TReg** – Total Regulation. This is the real-time fleet regulation capability (MW) that represents the active resource owner's ability to regulate. Ideally the value of this quantity should be the sum of the resource owner's non-zero AReg quantities for the majority of the hour, but must reflect any reductions in regulating capability as they occur (unit LFC limit restrictions, resource "off control" conditions, etc.). This value shall be calculated every 2 seconds and sent on a 2-second scan rate.
- **CReg** – Current Regulation. This is the real-time fleet regulation feedback (+/- MW) that represents the active position of the fleet with respect to the +/- TReg capability. Ideally the value of this quantity will track the RegA signal if the regulating fleet is

responding as prescribed. This value shall be calculated every 2 seconds and sent on a 2-second scan rate.

Determining Regulation Assignment

The PJM RTO's Regulating Requirement is a function of the day's load forecast, as determined by the PJM dispatcher. Each LSE is required to provide a share of the PJM Regulating Requirement. An LSE's actual hourly Regulation obligation is determined for the hour, after-the-fact, based on the LSE's total load in the PJM RTO, as follows:

$$\text{LSEs Regulation Obligation} = \left(\frac{\text{LSEs Load Allocation \%} \times \text{PJM Assigned Regulation}}{\text{PJM Assigned Regulation}} \right)$$

An LSE may satisfy its Regulation obligation by any of the following methods:

- Self-Scheduled Resources — An LSE can satisfy its Regulation obligation by self-scheduling Regulation.
- Bilateral Transaction — An LSE can make contractual arrangements with other PJM Members that are able to provide Regulation service.
- PJM Regulation Market Purchases — An LSE can purchase its Regulation obligation from the PJM Regulation Market, i.e., from the excess Regulation capability provided to PJM by Resource owners.

All Regulation offers reported to PJM must provide Regulation that has a quality standard of 75% or greater, as established by verification testing.

PJM Actions:

- Prior to the beginning of each day, PJM dispatcher determines the PJM RTO Regulating Requirement as follows:
 - The PJM Regulation Requirement is 1.0 % of the PJM Control Area's peak load forecast, as determined prior to the operating day.
- At 2230, PJM provides the following information to the Transmission Owners/Generation Owners for the LSE's, via the PJM ALL-CALL:
 - PJM RTO Regulation Requirement for the following day.

PJM Members Actions:

- Each LSE determines its estimated Regulation Obligation for the operating day based on its own forecast load and the information received via the PJM ALL-CALL.
- Resource owners view the hourly regulation market results via eMKT (available at least a half an hour before the operating hour) as to those resources to which regulation has been assigned. Resource owners that have self-scheduled Regulation on any of their resources inform the PJM dispatcher when those resources are on line and able to provide the self-scheduled Regulation.

- Once regulation on a resource is self-scheduled by a resource owner, it is no longer eligible to participate as a pool assigned regulating resource for the current operating day.
- If purchasing Regulation from another entity, the buyer and seller negotiate the transaction and the buyer submits the transaction through the Regulation Bilateral page of eMKT. The seller must then confirm the transaction via eMKT by 4:00pm the day after the operating day. The rules for these transactions are described in more detail later in this section of the manual.

Dispatching Regulation

PJM obtains the most cost efficient Regulation Ancillary Service available, as needed, to meet the PJM RTO's Regulation Requirement. PJM assigns Regulation in economic order based on the total cost of each available resource to provide Regulation, including real time opportunity cost and the resource's Regulation offer price. The AR signals are then automatically sent to the Resource Owners. Resource Owners are responsible for maintaining unit regulating capability. Exhibit 9 shows how the Regulation is assigned to the resources.

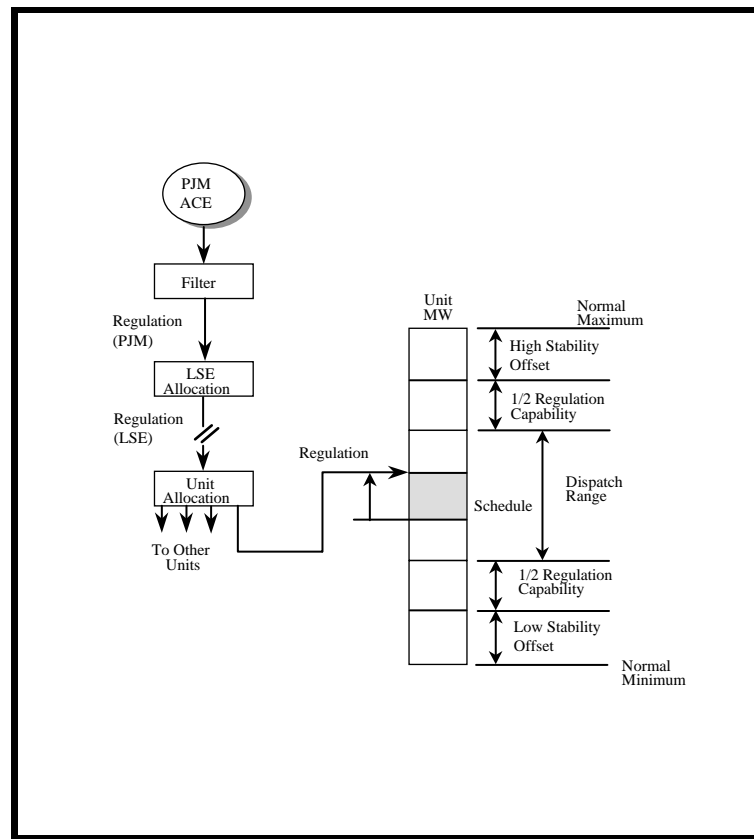


Exhibit 14: Area Regulation Assignment

PJM dispatcher re-assigns regulating capability as necessary to meet the PJM Control Area's Regulating Requirement. Market Sellers must comply with Regulation dispatch

signals that are transmitted by PJM. Market Sellers must operate their regulating resources as close to desired output levels, as practical, consistent with Good Utility Practices.

Regulation Deficiency

After the initial Regulation assignments are made, and throughout the operating hour, PJM Members report changes to their resource's regulating capabilities either by a phone call to PJM or by virtue of the TReg signal each company sends to PJM. If a resource becomes unable to supply its assigned amount of Regulation, the PJM dispatcher must deassign deficient resources and assign replacement Regulation to ensure that the total Regulation requirement is met. Such assignments are made economically based on each available resource's total cost to provide regulation, including real time opportunity cost and the resource's regulation offer price.

If, after assigning all available Regulation, the PJM Regulating Requirement is still not met, PJM dispatcher operates the system without the required amount of Regulation, logging such events.

In the event there is a loss of EMS communication between PJM and a resource owner, Current Regulation Assignments must be reassigned to another Resource Owner until EMS communication is reestablished.

Regulation Excess

If during the period an excess in assigned Regulation occurs and the total PJM RTO Regulation value exceeds the objectives by 15 MW or more, PJM dispatcher de-assigns Regulation economically based on each resource's total cost to provide regulation, including real time opportunity cost and the resource's regulation offer price.

PJM Actions:

- PJM dispatcher continuously monitors the Regulation deviation to assess Resource Owner fleet capability and reassigns Regulation as required.
- PJM's accounting staff determines the billing for the regulating service, according to the procedures in the ***PJM Manual for Operating Agreement Accounting (M-28)***.

PJM Member Actions:

- When initial assignments and reassignments are made, each affected Resource Owner dispatcher then updates the entity's regulating capability as defined by the Resource Owner TReg value.
- Participants report to the PJM dispatcher changes (of at least +/- 1 MW for duration greater than 15 minutes) to assigned Regulation capability.

Bilateral Transactions

One PJM Member may sell Regulation Ancillary Service to another PJM Member. The two members must agree on the MW amount of capability being sold, schedule Regulation accordingly, and submit the two-PJM Member Regulation transaction to PJM via eMKT.

PJM Actions:

None.

PJM Member Actions:

- All two-PJM Member transfers of regulating capability must be submitted as MW amounts via eMKT.
- The two members agree on the amount and duration of the Regulation transaction prior to the sale.
 - The “buying” member submits the MW amount of the two-PJM Member transaction, the selling member, and the start and end time of the transaction via eMKT.
 - The “selling” member confirms the transaction via eMKT by 4:00pm the day after the operating day.

Qualifying Regulating Resources

In order to ensure the quality of Regulation supplied to control the PJM RTO, a quality standard is developed. A resource must meet the quality standard to be permitted to regulate.

In general, there are two phases to qualifying a regulating resource:

- Certifying the resource
- Verifying regulating capability

An Area Regulation (AR) test is used for both certifying and verifying regulating capability for a resource.

Note: It must be emphasized that the Regulation test is not intended to test a resource’s governor response to power system frequency changes.

Regulation Test

The AR test is run during a continuous 40-minute period when, in the judgment of PJM test administrator, economic or other conditions do not otherwise change the base loading of the resources that are being tested. Changes in base loading for a resource during the test period invalidate the test for that resource.

During the AR test, the AR signal is fixed for the following four ten-minute periods:

- T0-T10
- T10-T20
- T20-T30
- T30-T40

The following steps describe the implementation of the test. It is assumed that the first non-zero AR signal is positive. (Note that the corresponding sequence in which the first non-zero AR signal is negative is equally valid.)

- **Step One:** T0-T10 — During this time period, the AR signal is equal to zero. This is the initiation of the AR test. This ten-minute period is provided so that the regulating resource settles at its base loading. At T10, the actual loading is sampled and the resulting value defines the base loading for that resource.
- **Step Two:** T10-T20 — During this 10 minute period, the AR signal is set to full raise.

- **Step Three:** T20-T30 — During this 10 minute period, the AR signal is set to zero.
- **Step Four:** T30-T40 — During this 10 minute period, the AR signal is set to full lower.
- **Step Five:** T40 — At this time, the AR signal is set to zero to terminate the test.

Exhibit 10 illustrates the Regulation test pattern.

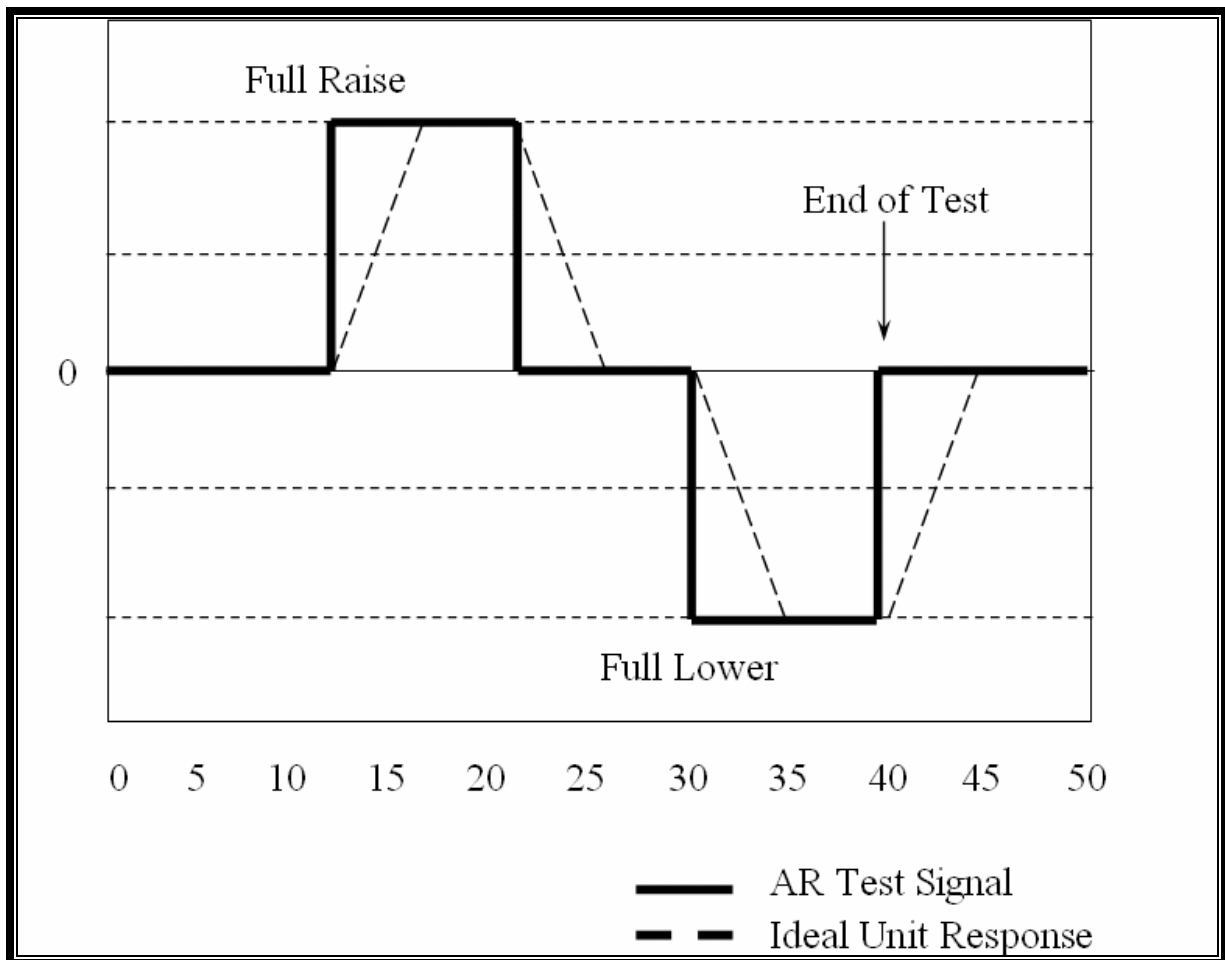


Exhibit 15: Regulation Test Pattern

Once an AR test is announced, a Resource Owner is not permitted to change any resource's Regulation assignment.

Scoring the AR test is based on compliance to two calculations:

- **Rate of Response Compliance** — The rate of response compliance is a measure of a resource's ability to achieve its Regulation assignment within five minutes.
- **Regulation Mismatch Compliance** — The Regulation mismatch compliance is a measure of a resource's ability to maintain its actual loading at a constant desired level for five minutes.

These two compliance values are averaged to yield a test score.

The Rate of Response Compliance is an average of three compliance calculations corresponding to the end of each of the three five-minute ramping periods (T15, T25, and T35) during the test.

The Rate of Response Compliance is determined as follows:

- At T15, the actual loading of the resource is sampled. This value is called AG15. Note, this is the actual loading and includes both the base generation and the AR response.

The Rate of Response Compliance at time T15 (RORC15) is:

$$RORC15 = 100 - \left[\left(\frac{ABS (Base Loading + AR Signal - AG15)}{Resource's Assigned AR} \right) \times 100 \right]$$

- This calculation is repeated at T25 and T35, yielding RORC25 and RORC35.
- The Rate of Response Compliance is:

$$Rate\ of\ Response\ Compliance = \frac{RORC15 + RORC25 + RORC35}{3}$$

The Regulation Mismatch Compliance is an average of three mismatch calculations, corresponding to samples taken during three, five minute periods when the resource response yields an actual loading equal to the base loading, plus the AR signal. These time periods are T15-T20, T25-T30, and T35-T40. During these time periods, the actual loading is sampled.

- During the time period T15-T20, a number of samples, n, of actual loading, AG1, AG2,, AGn, are taken. The mismatch for the M20 period is:

$$M20 = \frac{\sum_{i=1}^n \left[100 - \left(\left(\frac{ABS (Base Loading + AR - AG_i)}{Resource's Assigned AR} \right) \times 100 \right) \right]}{n}$$

where $AG_i = AG1, AG2, ..., AGn$

- This calculation is repeated for T25-T30 and T35-T40, yielding M30 and M40, respectively.
- The Regulation Mismatch Compliance is:

$$Regulation\ Mismatch\ Compliance = \frac{M20 + M30 + M40}{3}$$

The AR test score is determined by averaging the two compliance values.

$$Test\ Score = \frac{Rate\ of\ Response\ Compliance + Regulation\ Mismatch\ Compliance}{2}$$

The range for a valid test score is zero to one hundred percent. Test score results that are equal to 100% indicate the perfect, idealized response. All non-ideal responses yield positive values that decrease as the responses deviate from 100%. Any negative test results

default to zero. A valid test requires a continuous 40-minute period of uncorrupted test data. In the event that test data is of questionable integrity, validation is handled on a case-by-case basis.

Certifying Regulating Resource

A resource may be certified only after it achieves three consecutive scores of 75% or above. Resources providing dispatchable energy and regulation service need to provide testing at the low economic and high economic regulation limits. The first of these tests may be performed internally by the member following the PJM Regulation test procedure. Notification to perform a regulation test must be made to the PJM dispatcher at least 20 minutes before the test. PJM's dispatcher makes the final determination about whether a PJM administered test can be performed. Only one test may be performed on a resource each day.

Certifying Multiple Combustion Turbines or Hydro Units at a Single Site

Combustion Turbines and Hydro-generators operating under a single plant control system must have a minimum of three tests of the control system. In addition, the performance of the each of the units being certified must be demonstrated in at least one of these tests. The test format must follow PJM Regulation test procedure. High and low band requirements do not apply for CTs and Hydro units being certified.

Increasing Regulation Capability on a Resource

One Regulation Certification Test is required for each market resource to increase the Regulating Capability on the resource. This test must be administered by PJM.

PJM Actions:

- PJM maintains a historical database of individual resource Regulation test results and calculates all appropriate compliance information. Individual test results are provided via email to each participating LSE within three business days to facilitate a review and validation of results at the participant level.
- PJM will update the regulation bidding availability to reflect the new certification within 1 business day.

PJM Member Actions:

- For any tests performed internally by the members for the purpose of certification, the member will supply the resource, the time of the test and amount of MW being tested.

Continued Verification of Regulation Resources

A resource's compliance rating is defined as the sliding average of the five highest test scores (as described in the previous section) of the last seven valid AR tests, weighted by MW of Regulation assigned. If a regulating resource has a limited number of available AR test scores, the compliance rating calculation can use a minimum of three test scores:

- For a resource with three or fewer valid AR test scores, no tests are excluded from the compliance rating calculation.

- For a resource with only four valid AR test scores, exclude the lowest test score from the compliance rating calculation.
- For a resource with five or more valid AR test scores, exclude the two lowest test scores from the compliance rating calculation.

The resource's average compliance rating is then calculated as follows:

$$\text{Compliance Rating} = \frac{\sum (\text{Test Score}) \times (\text{Assigned Regulating Capability})}{\sum \text{Assigned Regulating Capability}}$$

PJM Actions:

- PJM maintains a historical database of individual resource Regulation test results and calculates all appropriate compliance information. Individual test results are provided via email to each participating member within three business days in order to facilitate a review and validation of results at the participant level.
- If the resource's compliance rating drops below 75% the resource will be removed from the market, and must re-certify (using the procedures described in the previous section) before rejoining the regulation market.

PJM Member Actions:

- After the last certification test results are submitted to PJM, PJM notifies LSEs of a resource's certification for Regulation within three business days.

Black Start Service

Black Start capability is necessary to restore the PJM transmission system following a blackout. Black Start Service shall enable PJM and LCCs to designate specific generators whose location and capabilities are required to re-energize the transmission system.

These designated resources, called black start units, are generating units that are able to start without an outside electrical supply or the demonstrated ability of a unit with a high operating factor (subject to PJM approval) to remain operating, at reduced levels, when automatically disconnected from the grid. The planning and maintenance of adequate black start capability for restoration of the PJM control area following a blackout represents a benefit to all transmission customers. All transmission customers must therefore take this service from PJM.

Black Start Service can be provided by units that participate in system restoration. Such units may be eligible for compensation under the Black Start Service. If a partial or system-wide blackout occurs, Black Start Service generating units can assist in the restoration of the PJM control area. Specific generating units identified in specific Transmission Owners' local restoration plan(s), have the capability and training required to start-up without the presence of a synchronized grid to provide the necessary auxiliary station power.

The Transmission Owner restoration plans are implemented if a partial or complete system blackout occurs.

Attachment A: PJM Instantaneous Reserve Check (IRC)

IRC - Definitions of Terms / Calculations

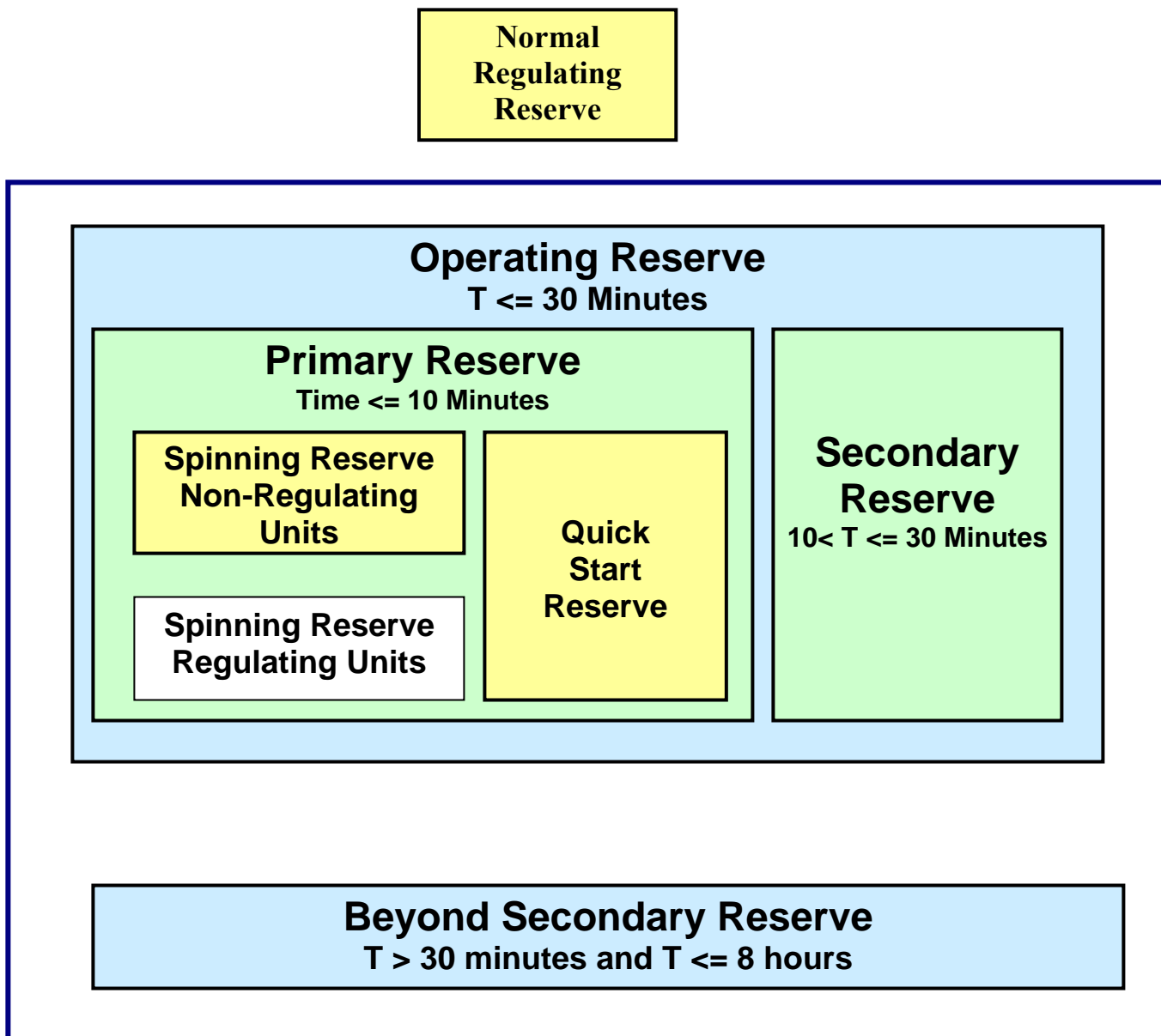


Exhibit 18: PJM Instantaneous Reserve Check Terms & Relationships

Type of Reserve	Description/Calculation
Normal Regulating Reserve (NRR)	$NRR = (\text{Base Point} + \text{AR assigned}) - \text{Current output.}$ $NRR = 0$ if no AR assigned to the unit

Spinning Reserve Regulating (SRR) SRR is the lesser of:

- a) Spin Ramp Rate * 10 minutes – Normal Regulating Reserve
- b) Spin Max (if none exists then Economic Max is used) – current output - Normal Regulating Reserve

Not to be less than 0

SRR = 0 if no AR assigned to the unit

Spinning Reserve Non-regulating Non-regulating Generation available within 10 minutes for Online Reserve Units

1. The Spinning Reserve Non-regulating is calculated as follows:

- Spinning Reserve = the lesser of:
 - (a) Spin Ramp Rate * 10 min
 - (b) Spin Max (if none exists then Economic Max is used) – Current MW Level
- Spinning Reserve Non-regulating = 0 if AR is assigned to the unit

Quickstart Reserve Generation available within 10 minutes for Offline Reserve Units

- Quickstart Reserve (Hydro) = Spin Max (if none exists then Economic Max is used) (limited by ramp rate * (10 minutes - TTS))
 - Quickstart Reserve (Non - Hydro) = Spin Max (if none exists then Economic Max is used) (limited by ramp rate * (10 minutes - TTS))
- Include: Offline Reserve Units that have a (Notification Time + TTS) ≤ 10 min
- Note: TTS = Time to Start

Primary Reserve Spinning Reserve Non-regulating + Spinning Reserve Regulating + Quick Start Reserve

Operating Reserve Generation available within 30 minutes for Online or Offline Reserve Units

- Operating Reserve = Offline + Online
- Offline is calculated as follows:
 - Offline = Spin Max (if none exists then Economic Max is used) (limited by Spin Ramp Rate * (30 minutes - TTS))
 - Include: Offline Reserve Units that have a (Notification Time + TTS) ≤ 30 min. (limited by Spin Ramp Rate * 30 minutes - TTS)
- Online is calculated as follows:
 - Online = the lesser of:

- a) ramp rate * 30 min
- b) Spin Max (if none exists then Economic Max is used) – Current MW Level

Note: Regulating Units are permitted to be included in the operating reserve calculation.

Note: If a Maximum Emergency Alert is issued, and Maximum Emergency is called into the capacity, Emergency Maximum should be used in place of Spin Max or Economic Maximum.

Secondary Reserve Operating Reserve - Primary Reserve

Beyond Secondary Reserve Generation available after 30 minutes but before 8 hours for Online and Offline Reserve Units

- **Beyond Secondary = Offline + Online**
- **Offline is calculated as follows:**
 - **Offline = Spin Max (if none exists then Economic Max is used)**
 - **Include: Offline Reserve Units that have a (Notification Time + TTS) > 30 min and <= 8 hours. Depending on the time the unit has been off line and the unit's definition of a Cold, Intermediate or Hot start, the Notification and TTS used will be either the Cold, Intermediate or Hot values.**
- **Online is calculated as follows:**
 - **Online = Spin Max (if none exists then Economic Max is used) – Current MW Level – Spin Ramp Rate * 30 min. If this results in a negative number, set to 0.**

Note: If a Maximum Emergency Alert is issued, and Maximum Emergency is called into the capacity, Emergency Maximum should be used in place of Spin Max or Economic Maximum.

Exhibit 19: Definitions of PJM Instantaneous Reserve Check Terms



Manual No. 002

Business Practices Manual

Energy and Operating Reserve Markets

Version 7.1 - DRAFT

Last Revised: July 26, 2007

TABLE OF CONTENTS

1. Introduction.....	1-1
1.1 Purpose of the Midwest ISO Business Practices Manuals	1-1
1.2 Purpose of this Business Practices Manual.....	1-1
1.3 References	1-2
2. Energy and Operating Reserve Markets Overview	2-1
2.1 Energy and Operating Reserve Markets Operation and Settlements.....	2-1
2.2 Market Modeling Terminology	2-3
2.2.1 Network Model.....	2-4
2.2.2 Commercial Model	2-4
2.2.3 Elemental Pricing Nodes	2-4
2.2.4 Aggregated Pricing Nodes.....	2-4
2.2.5 Commercial Pricing Nodes.....	2-5
2.2.6 Asset Owners	2-6
2.2.7 Market Participants.....	2-6
2.3 Roles and Responsibilities.....	2-7
2.3.1 Midwest ISO.....	2-7
2.3.2 Market Participants.....	2-10
2.3.3 Transmission Operators.....	2-11
2.3.4 Generation Owners/Operators	2-12
2.3.5 Load-Serving Entities	2-12
2.3.6 Market Support Services Providers	2-13
2.3.7 Local Balancing Authorities	2-13
2.3.8 Independent Market Monitor	2-13
2.4 Energy and Operating Reserve Markets System Components	2-14
2.5 Market Operations Tools	2-17
2.5.1 Financial Scheduling Software	2-18
2.5.2 Physical Scheduling Software	2-19
2.5.3 Midwest ISO Market Portal.....	2-21
3. Energy and Operating Reserve Market Requirements and Product Description	3-1
3.1 Regulating Reserve Product and Requirements.....	3-2
3.1.1 Regulating Reserve Product Description.....	3-2
3.1.2 Market-Wide Regulating Reserve Requirements	3-2

3.1.2.1	Calculation of Hourly Market-Wide Regulating Reserve Requirements - Initial	3-3
3.1.2.2	Calculation of Hourly Market-Wide Regulating Reserve Requirements - Final	3-3
3.2	Contingency Reserve Product and Requirements	3-4
3.2.1	Contingency Reserve Product Requirements	3-5
3.2.2	Market-Wide Contingency Reserve Requirements	3-5
3.3	Zonal Operating Reserve Requirements	3-6
3.3.1	Method To Establish Zonal Operating Reserve Requirements	3-6
3.3.2	Method to Establish Zonal Spinning Reserve Requirements	3-7
3.3.3	Method to Establish Hourly Zonal Regulating Reserve Requirements	3-8
3.4	Load Forecasting	3-8
3.4.1	High Level Description of Load	3-8
3.4.2	Use of Load Forecast	3-10
3.4.2.1	Reliability Assessment Commitment	3-10
3.4.2.2	Real-Time 5-Minute Dispatch	3-10
3.4.3	Source of Load Forecast	3-11
3.4.3.1	Reliability Assessment Commitment	3-11
3.4.3.2	Real-Time 5-Minute Dispatch	3-11
3.4.3.3	Pumped Storage Load	3-11
3.4.3.4	Non-Conforming Load and DRR-Type II Load Forecast	3-12
4.	Energy and Operating Reserve Markets Participation	4-1
4.1	Bilateral Transactions	4-2
4.1.1	Interchange Schedules	4-3
4.1.1.1	Schedule Types	4-3
4.1.1.1.1	Import Schedule	4-4
4.1.1.1.2	Export Schedule	4-5
4.1.1.1.3	Through Schedule	4-5
4.1.1.1.4	GFA Schedule	4-5
4.1.1.2	Interchange Schedule Application Types	4-5
4.1.1.2.1	Fixed Interchange Schedules	4-8
4.1.1.2.2	Dispatchable Interchange Schedules	4-9
4.1.1.2.3	Up-to-TUC Interchange Schedules	4-10
4.1.1.2.4	Fixed Dynamic Interchange Schedules	4-10

4.1.1.2.5	Grandfathered Carve Out Transactions	4-11
4.1.2	Financial Schedules	4-11
4.1.2.1	Rules for Financial Schedules.....	4-12
4.1.2.2	Types of Financial Bilateral Transactions.....	4-13
4.1.2.3	Day-Ahead Transmission Usage Charges for Financial Schedules	4-15
4.1.2.4	Real-Time Transmission Usage Charges for Financial Schedules	4-15
4.2	Resource Offer Requirements.....	4-16
4.2.1	Resource Qualifications and Eligibility to Provide Operating Reserve.....	4-16
4.2.1.1	Regulation Qualified Resource Requirements	4-16
4.2.1.1.1	Day-Ahead Resource Eligibility.....	4-17
4.2.1.1.2	Real-Time Resource Eligibility	4-17
4.2.1.2	Spin Qualified Resource Requirements	4-18
4.2.1.2.1	Day-Ahead Resource Eligibility.....	4-19
4.2.1.2.2	Real-Time Resource Eligibility	4-19
4.2.1.3	Supplemental Qualified Resource Requirements.....	4-19
4.2.1.3.1	Day-Ahead Resource Eligibility.....	4-20
4.2.1.3.2	Real-Time Resource Eligibility	4-20
4.2.2	Generation Resources and DRR-Type II Offer Requirements	4-21
4.2.2.1	Offer Information Summary	4-21
4.2.2.2	Economic Offer Data	4-23
4.2.2.2.1	Energy Offer Curves (MW/Price Pairs)	4-23
4.2.2.2.2	Operating Reserve Offers	4-24
4.2.2.2.3	Start-Up Offers and No-Load Offers.....	4-25
4.2.2.3	Commitment Operating Parameter Offer Data	4-25
4.2.2.4	Dispatch Operating Parameter Offer Data	4-28
4.2.2.4.1	Dispatch Limits and Ramp Rates	4-28
4.2.2.4.2	Dispatch Band Limits	4-30
4.2.2.4.3	Temperature Sensitive Maximum Limits.....	4-33
4.2.2.4.4	Resource Offer Commitment Status.....	4-34
4.2.2.4.5	Resource Offer Dispatch Status.....	4-35
4.2.2.4.6	Resource Self-Schedule.....	4-36
4.2.3	Demand Response Resources-Type I (DRR-Type I) Offer Requirements.....	4-37
4.2.3.1	Offer Information Summary	4-37

4.2.3.2	Economic Offer Data	4-39
4.2.3.2.1	Energy Offer.....	4-39
4.2.3.2.2	Operating Reserve Offers	4-39
4.2.3.3	Commitment and Dispatch Operating Parameter Offer Data	4-39
4.2.3.3.1	DRR-Type I Commitment Status	4-42
4.2.3.3.2	DRR-Type I Offer Dispatch Status	4-42
4.2.3.3.3	DRR-Type I Self-Schedule.....	4-43
4.2.4	External Asynchronous Resources (EAR) Offer Requirements.....	4-43
4.2.4.1	Offer Information Summary	4-44
4.2.4.2	Economic Offer Data	4-45
4.2.4.2.1	Energy Offer Curves (MW/Price Pairs)	4-45
4.2.4.2.2	Operating Reserve Offers	4-46
4.2.4.3	Dispatch Operating Parameter Offer Data	4-47
4.2.4.3.1	Dispatch Limits and Ramp Rates	4-47
4.2.4.3.2	EAR Offer Dispatch Status	4-49
4.2.4.3.3	EAR Offer Self-Schedule.....	4-50
4.2.5	Resource Offer Hierarchy.....	4-51
4.2.6	Resource Modeling.....	4-52
4.2.6.1	Demand Response Resources-Type I	4-52
4.2.6.2	Demand Response Resources-Type II	4-55
4.2.6.3	External Asynchronous Resources.....	4-57
4.2.6.4	Jointly-Owned Unit Resources	4-58
4.2.6.5	Combined Cycle Resources	4-59
4.2.6.6	Cross Compound Resources	4-60
4.2.6.7	Energy Limited Resources	4-60
4.2.6.8	System Support Resources.....	4-60
4.2.6.9	Generation Resources Under 5 MWs.....	4-61
4.2.6.10	Intermittent Resources	4-62
4.2.6.11	Non-Telemetered Resources	4-62
4.3	Demand Bids	4-62
4.3.1	Fixed Demand Bids	4-63
4.3.2	Price-Sensitive Demand Bids	4-63
4.4	Virtual Transactions.....	4-65

4.4.1	Virtual Supply Offers	4-65
4.4.2	Virtual Bids.....	4-67
5.	Locational Marginal Prices and Market Clearing Prices.....	5-1
5.1.1	LMP Components.....	5-1
5.1.1.1	Marginal Losses Component (MLC_i) Calculation	5-3
5.1.1.2	Marginal Congestion Component (MCC_i) Calculation.....	5-4
5.1.1.3	Marginal Energy Component (MCC_r) Calculation.....	5-5
5.1.1.4	Locational Marginal Price Calculation	5-5
5.1.1.5	Actual Calculation of LMPs and Associated LMP Components.....	5-5
5.1.2	Hub LMP Calculation.....	5-6
5.1.3	Load Zone Price Calculation	5-6
5.1.4	Multi-Element Flowgate Shadow Price Calculation	5-7
5.1.5	External Interface Price Calculation	5-8
5.2.1	Demand Curves	5-10
5.2.1.1	Market-Wide Operating Reserve Demand Curve Development.....	5-11
5.2.1.2	Zonal Operating Reserve Demand Curve Development.....	5-15
5.2.1.3	Market-Wide Regulating Reserve Demand Curve Development	5-17
5.2.1.4	Zonal Regulating Reserve Demand Curve Development	5-18
5.2.2	Market Clearing Price Calculation Details	5-19
5.2.3	Market Clearing Price Calculation Examples.....	5-22
5.2.3.1	Co-optimized Clearing Example – No Scarcity Pricing	5-22
5.2.3.2	Co-optimized Clearing Example – Contingency Reserve Scarcity	5-25
6.	Reliability Assessment Commitment Activities.....	6-1
6.1	RAC Process Input Assumptions.....	6-2
6.1.1	Forecasting Load	6-3
6.1.2	Operating Reserve Requirements	6-3
6.1.3	Pre-Scheduling Interchange Schedules Greater than One Day Out.....	6-3
6.1.4	Submitting Resource Offers for Reliability Assessment Commitment	6-4
6.1.5	Committing Long Start-Up Resources	6-5
6.1.6	Scheduling Outages	6-6
6.1.7	Maintaining Facility Ratings	6-6
6.2	RAC Processes Under Shortage Conditions.....	6-6
6.2.1	Emergency Energy Purchases.....	6-7

6.3	RAC Processes Under Surplus Conditions.....	6-8
6.4	RAC Processes Results.....	6-8
7.	Day-Ahead Energy and Operating Reserve Market Activities.....	7-1
7.1	Market Participant Activities	7-3
7.1.1	Submitting Resource Offers	7-3
7.1.2	Submitting Bids and Virtual Supply Offers.....	7-4
7.1.3	Submitting Interchange Schedules	7-4
7.2	Midwest ISO Activities	7-4
7.2.1	Energy and Operating Reserve Markets Requirements.....	7-5
7.2.2	Interchange Schedules	7-5
7.2.3	Day-Ahead Energy and Operating Reserve Market Clearing.....	7-7
7.2.3.1	Clearing Under Shortage Conditions	7-9
7.2.3.2	Clearing Under Surplus Conditions	7-9
7.3	Monitoring and Mitigating Day-Ahead Energy and Operating Reserve Market.....	7-10
8.	Real-Time Energy and Operating Reserve Market Activities.....	8-1
8.1	Market Participant Activities	8-2
8.1.1	Submitting Real-Time Resource Offers	8-2
8.1.1.1	Real-Time Resource Offer Rules.....	8-3
8.1.2	Submitting Real-Time Interchange Schedules	8-4
8.2	Midwest ISO Activities	8-5
8.2.1	Checkout of Interchange Schedules.....	8-5
8.2.2	Operating Reserve Requirements	8-6
8.2.3	Real-Time Energy and Operating Reserve Market Clearing.....	8-6
8.2.3.1	Clearing Under Shortage Conditions	8-8
8.2.3.2	Clearing Under Surplus Conditions	8-9
8.2.4	Regulating Reserve Deployment	8-9
8.2.5	Excessive/Deficient Energy Deployment Charges	8-9
8.2.6	Contingency Reserve Deployment	8-10
8.2.7	Contingency Reserve Deployment Failure and Consequence	8-11
8.2.8	Inadvertent Interchange	8-12
8.2.9	Calculating Ex-Post LMPs and MCPs.....	8-12
8.3	Local Balancing Authority Activities	8-13
8.3.1	Providing Load Forecast.....	8-13

8.3.2	Providing DRR-Type II Load Forecast	8-13
8.3.3	Implementing Midwest ISO Setpoint Instructions	8-14
8.4	Monitoring and Mitigating Real-Time Energy and Operating Reserve Market.....	8-14
9.	Energy and Operating Reserve Markets Closure Activities	9-1
9.1	Ex-Post LMP/MCP Calculation	9-2
9.1.1	Ex-Post LMP/MCP Calculation Sequence	9-2
9.1.2	Ex-Post LMP/MCP Calculation Process	9-3
9.1.3	Ex-Post LMP/MCP Verification.....	9-4
9.1.3.1	Verification Process	9-5
9.1.3.1.1	Midwest ISO Verification Actions.....	9-5
9.1.4	LMP/MCP Replacements	9-6
9.1.5	Hourly Ex-Post LMPs and Time-Weighted MCPs.....	9-6
9.1.5.1	Hourly Bus LMPs	9-6
9.1.5.2	Hourly Aggregate Node LMPs	9-9
9.1.6	Hourly Time-Weighted MCPs.....	9-10
9.1.7	LMP/MCP Results Posting.....	9-11
9.2	Hourly Post Operations Processor Calculations	9-11
9.2.1	Hourly Resource Operating Reserve Delta MWs and MCPs	9-12
9.2.2	Excessive/Non-Excessive/Deficient Energy.....	9-13
9.2.2.1	Excessive Energy Payment Rate.....	9-14
9.2.3	Regulation Revenue Adjustment.....	9-16
9.3	After-the-Fact Schedules	9-21
9.4	After-the Fact Check Out.....	9-22
9.4.1	Regional Reporting Procedures	9-22

List of Exhibits:

Exhibit 2-1: Energy and Operating Reserve Markets – Timeline Overview	2-3
Exhibit 2-2: CPNode Types	2-5
Exhibit 2-3: DART Components Overview.....	2-15
Exhibit 2-4: Market Operations Tools	2-18
Exhibit 2-5: PSS Process-Overview	2-21
Exhibit 3-1: Operating Reserve Product Hierarchy	3-1
Exhibit 3-2: Combining Conforming, Non-Conforming and DRR-Type II Load Forecast	3-12

Exhibit 4-1: Market Participation Options.....	4-1
Exhibit 4-2: Bilateral Transactions Terminology	4-2
Exhibit 4-3: Interchange Schedules and GFA Schedules	4-4
Exhibit 4-4: Energy and Market Transaction Type with OASIS, DART, and Settlement Info.....	4-7
Exhibit 4-5: Energy and Market Transaction Types.....	4-8
Exhibit 4-6: Financial Schedule – Definition	4-12
Exhibit 4-7: Pseudo-Ties (Real-Time Financial Schedules).....	4-14
Exhibit 4-8: Grandfathered Agreements (Day-Ahead Financial Schedules).....	4-15
Exhibit 4-9: Resource Eligibility Summary for Provision of Operating Reserve.....	4-16
Exhibit 4-10: Generation Resource and DRR-Type II Economic Data Summary	4-21
Exhibit 4-10A: Generation Resource and DRR-Type II Operating Parameter Data Summary....	4-22
Exhibit 4-11: Types of Energy Offers.....	4-24
Exhibit 4-12: Generation Resource and DRR-Type II Commitment Offer Parameters	4-25
Exhibit 4-13: Generation Resource & DRR-Type II Operation Timeline	4-28
Exhibit 4-14: Dispatch Limits.....	4-29
Exhibit 4-15: Overall Ramp Rate and Limit Use.....	4-29
Exhibit 4-16: Dispatch Band Ramp Rate and Limit Use	4-31
Exhibit 4-17: Dispatch Band Use Example	4-32
Exhibit 4-18: Weather Curve Example.....	4-34
Exhibit 4-19: Valid Dispatch Status Selections	4-35
Exhibit 4-20: DRR-Type I Offer Data Summary.....	4-38
Exhibit 4-21: DRR-Type I Offer Parameters.....	4-40
Exhibit 4-22: DRR-Type I Operation Timeline.....	4-42
Exhibit 4-23: Valid DRR-Type I Commit and Dispatch Status Combinations	4-43
Exhibit 4-24: External Asynchronous Resource Offer Data Summary	4-44
Exhibit 4-25: Types of EAR Energy Offers.....	4-46
Exhibit 4-26: EAR Dispatch Limits.....	4-47
Exhibit 4-27: Overall Limit and Ramp Rate Use.....	4-48
Exhibit 4-28: Valid Dispatch Status Selections	4-49
Exhibit 4-29: Real-Time Resource Offer Hierarchy.....	4-51
Exhibit 4-30: Single EPNode DRR-Type I.....	4-53
Exhibit 4-31: Multiple EPNode DRR-Type I	4-53
Exhibit 4-32: DRR-Type II Modeling Example	4-55

Exhibit 4-34: DRR-Type II Hourly Settlement Calculations.....	4-57
Exhibit 4-34: EAR Modeling and Systems Interaction.....	4-58
Exhibit 4-35: Price-Sensitive Demand Bid Submittal Example	4-64
Exhibit 4-36: Virtual Supply Offer Submittal Example	4-66
Exhibit 4-37: Virtual Supply Offer Example.....	4-67
Exhibit 4-38: Virtual Bid Submittal Example.....	4-68
Exhibit 4-39: Virtual Demand Bid Example.....	4-69
Exhibit 5-1: Market-Wide Operating Reserve Demand Curve Calculation	5-14
Exhibit 5-2: Market-Wide Operating Reserve Demand Curve Example.....	5-14
Exhibit 5-3: Zonal Operating Reserve Demand Curve Development	5-16
Exhibit 5-4: Market-Wide Regulating Reserve Demand Curve Development.....	5-18
Exhibit 5-5: Zonal Regulating Reserve Demand Curve Development.....	5-19
Exhibit 5-6: Co-optimized Clearing, No Scarcity – Assumptions	5-22
Exhibit 5-7: Co-optimized Clearing, No Scarcity – Results	5-23
Exhibit 5-8: Co-optimized Clearing, Contingency Reserve Scarcity – Assumptions.....	5-25
Exhibit 5-9: Co-optimized Clearing, Contingency Reserve Scarcity – Results.....	5-26
Exhibit 6-1: RAC Timeline.....	6-2
Exhibit 7-1: Day-Ahead Energy and Operating Reserve Market Activities Timeline	7-1
Exhibit 7-2: Data Flow for Day-Ahead Energy and Operating Reserve Market	7-2
Exhibit 8-1: Real-Time Energy and Operating Reserve Market Activities Timeline.....	8-1
Exhibit 8-2: Data Flow for Real-Time Energy and Operating Reserve Market (Excluding RAC)	8-2
Exhibit 9-1: Market Closure Activity Timeline.....	9-1
Exhibit 9-2: Ex-Post LMP Calculation - Timeline	9-2
Exhibit 9-3: Hourly MCP Calculation Example	9-13
Exhibit 9-4: Excessive/Deficient Energy Determination	9-14
Exhibit 9-5: Excessive Energy Price Determination – Piece-wise Linear	9-15
Exhibit 9-6: Excessive Energy Price Determination – Block	9-16
Exhibit 9-7: Regulation Revenue Adjustment Credit - Net Regulation Deployment Up	9-18
Exhibit 9-8: Regulation Revenue Adjustment Charge - Net Regulation Deployment Up.....	9-19
Exhibit 9-9: Regulation Revenue Adjustment Charge - Net Regulation Deployment Down.....	9-20
Exhibit 9-10: Regulation Revenue Adjustment Credit - Net Regulation Deployment Down	9-21

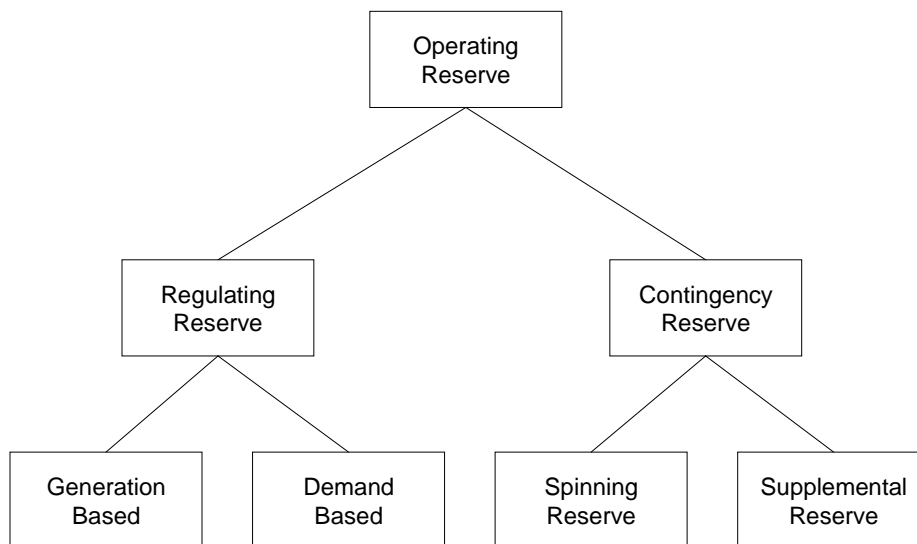
3. Energy and Operating Reserve Market Requirements and Product Description

The following four products are traded in both the Day-Ahead and Real-Time Energy and Operating Reserve Markets to meet the Midwest ISO Energy and Operating Reserve requirements:

- Locational Energy;
- Regulating Reserve;
- Spinning Reserve;
- Supplemental Reserve.

Locational Energy is a commodity that is both purchased and sold by market participants to meet Day-Ahead Energy requirements, which are based upon Demand Bids, Virtual Bids and Export Schedules, and Real-Time Energy requirements, which are based upon actual real-time metered deviations from Day-Ahead Energy requirements. Regulating Reserve, Spinning Reserve and Supplemental Reserve represent ancillary services procured to meet Midwest ISO Operating Reserve requirements to ensure reliable operation of the Midwest ISO Balancing Authority. The three Operating Reserve products are part of the Operating Reserve Hierarchy illustrated in Exhibit 3-1:

Exhibit 3-1: Operating Reserve Product Hierarchy



Based on the Operating Reserve Hierarchy, Operating Reserve is comprised of Regulating Reserve and Contingency Reserve, Regulating Reserve is comprised of Generation-based Regulating Reserve and Demand-based Regulating Reserve and Contingency Reserve is comprised of Spinning Reserve and Supplemental Reserve. This Section describes the Operating Reserve products and the methods used by the Midwest ISO to calculate the Market-Wide and Zonal Regulating Reserve Requirements.

3.1 Regulating Reserve Product and Requirements

The Regulating Reserve product and the methods used by the Midwest ISO to set the Market-Wide and Zonal Regulating Reserve Requirements are described in the following subsections.

3.1.1 Regulating Reserve Product Description

Regulating Reserve products cleared in either the Day-Ahead or Real-Time Energy and Operating Reserve Market to meet either the Zonal or Market-Wide Regulating Reserve Requirements must meet the following criteria:

- All cleared Regulating Reserve products must be fully deployable in both the regulation-up and regulation-down directions within the Regulation Response Time. The Midwest ISO will determine automatically the maximum amount of Regulating Reserve that is fully deployable from a specific Resource within the Regulation Response Time based on active ramp rates and/or the clearing of other products on the Resource.
- The Regulation Response Time may be reviewed and adjusted if it is determined by the Midwest ISO that the current setting is not providing acceptable reliability compliance at a reasonable cost. The initial Regulation Response Time will be set at 300 seconds or 5.0 minutes.
- All Regulating Reserve products must be supplied by Regulation Qualified Resources, where Regulation Qualified Resources are Resources that are registered as such, meet the requirements outlined in Section 4.2 of this BPM for Regulation Qualified Resources and have their hourly Regulation Qualified Flag set to "True" for the Operating Hour in question.
- The amount of Regulating Reserve product that can be cleared on Demand Response Resources - Type II may be limited based on Electric Reliability Organization and/or applicable Regional Reliability Organization standards. This could result in price separation between the Generation-based Regulating Reserve product and Demand-based Regulating Reserve product.

3.1.2 Market-Wide Regulating Reserve Requirements

The Midwest ISO sets the Market-Wide Regulating Reserve Requirements based upon the follow criteria:

- The Midwest ISO Market-Wide Regulating Reserve Requirement will be established for each hour of the Operating Day by 1100 EST the day prior to the Operating Day. These hourly requirements will apply to both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. The Midwest ISO Market-Wide Regulating Reserve Requirement may be adjusted after 1100 EST for the Real-Time Energy and Operating Reserve Market if necessary due to an Emergency operating condition.
- The hourly Market-Wide Regulating Reserve Requirements will be reviewed daily to ensure acceptable compliance levels with Electric Reliability Organization standards and applicable Regional Reliability Organization standards related to control performance. Acceptable compliance levels are performance levels that meet reliability standards at a reasonable cost. At the present time, Market-Wide Regulating Reserve Requirements will be set to comply with Electric Reliability Organization Standard BAL-0-001-0 Control Performance Standard 1 (CPS1) and Control Performance Standard 2 (CPS2). Should these standards be modified, replaced or terminated, or should additional standards related to control performance be adopted, the method used to set the hourly Market-Wide Regulating Reserve Requirements will be updated accordingly. The specific methods to be used to set the hourly Market-Wide Regulating Reserve Requirement are described in Sections 3.1.2.1 and 3.1.2.2.

3.1.2.1 Calculation of Hourly Market-Wide Regulating Reserve Requirements - Initial

- Initially, the hourly Market-Wide Regulating Reserve Requirement will be set equal to a percentage of hourly forecasted load. The initial percentage used will be 1.0%, but this percentage may be adjusted upward or downward based on the projected rolling 12-month CPS1 compliance and monthly CPS2 compliance factor.
- This method will be utilized until sufficient historic data is collected to support the final method described in Section 3.1.2.2. It is expected that at least 6 months worth of historic data will be required to support this final method (i.e., one peak season and one off-peak season).
- Should it be necessary to adjust the Regulation Response Time, the initial method will be resumed to allow for collection of historic data based on the new Regulation Response Time.

3.1.2.2 Calculation of Hourly Market-Wide Regulating Reserve Requirements - Final

- The final method used to set the hourly Market-Wide Regulating Reserve Requirement is only as final as the control performance standards that drive it. Based on the current control performance standards, the final method will be based on achieving a targeted monthly compliance factor for CPS2 of 92%.

- In the unlikely event that the projected rolling 12-month CPS1 compliance for the end of the month is less than 100%, the hourly Market-Wide Regulating Reserve Requirements will be increased by 10% until the projected CPS1 compliance at the end of the current month is 100% or greater.
- Prior to determining the hourly Market-Wide Regulating Reserve Requirement, the targeted daily CPS2 compliance factor will be determined as the daily compliance factor that will yield a monthly CPS2 compliance factor of 92% taking into consideration the actual daily CPS2 compliance factors for all days in the month two or more days prior to the Operating Day and assuming i) a 90% daily CPS2 compliance factor for all days in the month after the Operating Day and ii) a daily CPS2 compliance factor for the day prior to the Operating day equal to the targeted daily CPS2 compliance factor determined for that day. In no case will the targeted daily CPS2 compliance factor be set below 80%.
- Once the targeted daily CPS compliance factor has been determined, an optimization tool will be used to set the hourly Market-Wide Regulating Reserve Requirement in a manner that minimizes the cost-weighted Market-Wide Regulating Reserve for the Operating Day while achieving the targeted daily CPS compliance factor. The cost weighting factors will be selected based on the hourly load forecast and will be based on historic procurement cost per MW for Regulating Reserve for different system load levels as tracked by the Midwest ISO. Constraints will be introduced into the optimization tool to ensure the projected daily CPS2 compliance factor is greater than or equal to the targeted daily CPS2 compliance factor and to make sure the projected hourly CPS2 compliance factor is no less than 80% for any given hour.
- The projected daily CPS2 compliance factor will be equal to the sum of the projected hourly CPS2 compliance factors divided by 24. The projected hourly CPS2 compliance factor will be based on a linearized statistical distribution obtained from historic compliance data.

Note: A white paper will be released by the Midwest ISO on or before June 30, 2007 providing additional detail on how the Market-Wide Regulating Reserve Requirement optimization tool will work and what data inputs will be utilized.

3.2 Contingency Reserve Product and Requirements

The Contingency Reserve product and the methods used by the Midwest ISO to set the Market-Wide and Zonal Contingency Reserve Requirements are described in the following subsections.

3.2.1 Contingency Reserve Product Requirements

Contingency Reserve products cleared in either the Day-Ahead or Real-Time Energy and Operating Reserve Market to meet either the Zonal or Market-Wide Contingency Reserve Requirements must meet the following criteria:

- All cleared Contingency Reserve must be fully deployable within the Contingency Reserve Deployment Period. The Midwest ISO will determine automatically the maximum amount of Contingency Reserve that is fully deployable from a specific Resource within the Contingency Reserve Deployment Period based on active ramp rates and/or the clearing of other products on the Resource.
- The Contingency Reserve Deployment Period will be governed by Reliability standards, but in no case will be set greater than 10.0 minutes. Based on ERO Standard BAL 002-0, a Balancing Authority has 15.0 minutes (the Disturbance Recovery Period) to return its Area Control Error to the lesser of zero or the pre-disturbance Area Control Error level. The Midwest ISO currently allows five minutes to notify Resources to deploy Contingency Reserve after the occurrence of a disturbance which requires a Contingency Reserve Deployment Instruction. Therefore, the Midwest ISO will set the Contingency Reserve Deployment Period at 10.0 minutes, which is the difference between the Disturbance Recovery Period (15.0 minutes) and the notification time (5.0 minutes).
- Contingency Reserve will be comprised of Spinning Reserve and Supplemental Reserve. Spinning Reserve is Contingency Reserve supplied from Spin Qualified Resources whereas Supplemental Reserve is Contingency Reserve supplied from Supplemental Qualified Resources that are not Spin Qualified Resources. However, it is important to note that Spin Qualified Resources may supply Supplemental Reserve through product substitution.

3.2.2 Market-Wide Contingency Reserve Requirements

The Midwest ISO sets the Market-Wide Regulating Reserve Requirements based upon the follow criteria:

- The Midwest ISO Market-Wide Contingency Reserve requirement will be established for each hour of the Operating Day by 1100 EST the day prior to the Operating Day and will be the generally be same value in each hour⁴. These hourly requirements will apply to both the Day-Ahead and Real-Time Energy and Operating Reserve Markets. The hourly Midwest ISO Market-Wide Contingency Reserve Requirement will be set equal to the most restrictive requirement mandated by Electric Reliability Organization standards,

⁴ The Market-Wide Contingency Reserve Requirement may change in some hours during the Operating Day based upon changes to the most severe system contingency.

applicable Regional Reliability Organization standards or applicable Contingency Reserve Sharing Agreement requirement allocations. In no case will the hourly Midwest ISO Market-Wide Contingency Reserve requirement be set less than the largest single supply contingency (Resource or transmission). Currently, Electric Reliability Organization Standard BAL-002-0 indicates that, *"As a minimum, the Balancing Authority or Reserve Sharing Group shall carry enough Contingency Reserve to cover the most severe single Contingency"*. The Midwest ISO Market-Wide Contingency Reserve requirement may be adjusted after 1100 EST for the Real-Time Energy and Operating Reserve Market if one or more events result in a different requirement level.

- The hourly Market-Wide Spinning Reserve requirement will be equal to the greater of i) the most restrictive frequency responsive Contingency Reserve requirement, expressed in MW or as a percent of Contingency Reserve, specified by Electric Reliability Organization standards, applicable Regional Reliability Organization standards and/or applicable Contingency Reserve Sharing Agreements or ii) the most restrictive spinning reserve requirement, expressed in MW or as a percent of Contingency Reserve, specified by Electric Reliability Organization standards, applicable Regional Reliability Organization standards and/or applicable Contingency Reserve Sharing Group agreements.
- Electric Reliability Organization Standard BAL-002-0 indicates that, following a supply contingency, a Balancing Authority or Reserve Sharing Group must restore their Contingency Reserve within the Contingency Reserve Restoration Period, which is defined in the standard as the 90 minute period following the end of the Disturbance Recovery Period. During the Contingency Reserve Restoration Period, the Real-Time Energy and Operating Reserve Market will linearly ramp the Market-Wide Contingency Reserve Requirement back up to its pre-disturbance level. However, should there be capacity available to clear additional Market-Wide Contingency Reserve, the Real-Time Energy and Operating Reserve Market will clear additional Market-Wide Contingency Reserve up to the pre-disturbance Market-Wide Contingency Reserve requirement.

3.3 Zonal Operating Reserve Requirements

The Midwest ISO sets the Zonal Operating Reserve Requirements based upon the follow criteria:

3.3.1 Method To Establish Zonal Operating Reserve Requirements

The Midwest ISO identifies Reserve Zones and Zonal Operating Reserve Requirements through Reserve Zone Studies performed two days prior to each Operating Data. As such, Reserve Zone definitions may change from day to day based on the results of the studies but will remain fixed once established for both the Day-Ahead and Real-Time Operating Reserve Market. Reserve Zones are needed to accomplish two

goals: (1) to identify a minimum Operating Reserve requirement within the Reserve Zone to meet reliability requirements of the Reserve Zone; and (2) to disperse the clearing of Operating Reserve on Resources throughout the Midwest ISO Balancing Authority Area in an effort to avoid potential adverse conditions that may result when all Operating Reserves are cleared within a localized area. Therefore, in addition to establishing Market-Wide Operating Reserve Requirements, minimum Operating Reserve requirements must also be established for each Reserve Zone. Independent minimum requirements will be established for Regulating Reserve, and Spinning Reserve for each of the Reserve Zones. The Reserve Zone Study only establishes the Reserve Zone definitions and the total minimum Operating Reserve requirements in each Reserve Zone. The minimum Zonal Spinning Reserve Requirement in each Reserve Zone is established as described under Section 3.3.2 and the minimum Zonal Regulating Reserve Requirement is established as described under Section 3.3.3.

Reserve Zones and their associated minimum Operating Reserve requirements are determined using a four step process:

- Utilizing a network model representation for the target study period, generation in the case is allowed to re-dispatch to identify all transmission constraints that could occur.
- This list of constraints is screened by a set of criteria to limit the constraints only to those that will have a direct impact on Reserve Zone determination.
- Once a final set of constraints is identified, Resources in the Reserve Zone are grouped or clustered based on their impact on all of the remaining constraints. The groups of Resources are candidate Reserve Zones.
- Candidate Reserve Zones are tested by simulating the loss of each Resource inside the candidate Reserve Zone and importing from the Resources with the highest impact on the constraints identified in Step 3 until a constraint limit is reached or the lost Resource is fully replaced. This Step is repeated for each Resource in each candidate Reserve Zone. The minimum Operating Reserve requirement is the largest difference between the Resource MW lost and the resulting import capability. If the largest difference is zero, then the Reserve Zone is not needed and is dropped.

The results of the Reserve Zone Study identifies the number of Reserve Zones required and the Resource CPNodes that are included within each Reserve Zone and the minimum Operating Reserve requirement for each Reserve Zone.

3.3.2 Method to Establish Zonal Spinning Reserve Requirements

- The formula for determining the hourly Zonal Spinning Reserve Requirement for a specific Reserve Zone is as follows:

Hourly Zonal Spinning Reserve Requirement

$$= 25\% * \text{Market-Wide Spinning Reserve Percentage}$$

$$* \text{Zonal Contingency Reserve Requirement}$$

- Should the hourly Spinning Reserve Requirement for a specific Reserve Zone be calculated to be 10 MW or less, the hourly minimum Spinning Reserve Requirement for that Reserve Zone will be automatically set to 0 MW.

3.3.3 Method to Establish Hourly Zonal Regulating Reserve Requirements

The Midwest ISO sets the Zonal Regulating Reserve Requirements based upon the follow criteria:

- The hourly Regulating Reserve Requirement for a specific Reserve Zone will be driven by the percentage of Regulation Qualified Resource capacity that is located within the Reserve Zone in a specific hour. This percentage will be referred to as the Hourly Zonal Regulation Capacity Percentage.
- The formula for determining the hourly Zonal Regulating Reserve Requirement for a specific Reserve Zone is as follows:

$$\text{Hourly Zonal Regulating Reserve Requirement}$$

$$= 25\% * \text{Hourly Zonal Regulation Capacity Percentage}$$

$$* \text{Hourly Market-Wide Regulating Reserve Requirement}$$

- Should the hourly Zonal Regulating Reserve Requirement for a specific Reserve Zone be calculated to be 10 MW or less, the hourly minimum Zonal Regulating Reserve Requirement for that Reserve Zone will be automatically set to 0 MW.

3.4 Load Forecasting

This subsection describes how the Midwest ISO develops load forecasts for use in the Real-Time Energy and Operating Reserve Market

3.4.1 High Level Description of Load

The Midwest ISO needs a forecast of Load for two purposes:

- The RAC process performed each day for the next several days and also for any RAC process performed current day for future hours of that day
- The Real-Time 5-minute dispatch

The values that the load forecast represents for each of these two purposes is the same and conceptually can be defined as follows:

4.2 Resource Offer Requirements

Resource Offers are submitted by MPs at Resource CPNodes for the purpose of selling Energy and Operating Reserve into the Day-Ahead and Real-Time Energy and Operating Reserve Markets and can be submitted for all types of Resources. There are four types of Resources for which MPs may submit Offers: Generation Resources (including Jointly-Owned Generation Resources, Combined Cycle Resources, Cross Compound Resources, External Pseudo-Tied Generation Resources, Energy Limited Resources and Intermittent Resources), Demand Response Resources-Type I (DRR-Type I), Demand Response Resources-Type II (DRR-Type II) and External Asynchronous Resources. DRR-Type II Offer requirements are identical to Generation Resource Offer requirements and thus are combined under Section 4.2.2. Resource qualifications to provide Operating Reserve and Offer parameters are discussed for each Resource category (with Generation Resource and DRR-Type II combined) in the following Subsections.

4.2.1 Resource Qualifications and Eligibility to Provide Operating Reserve

The following subsections describe the requirements that must be met by any Resource in order to be qualified to submit Operating Reserve Offers for use in the Energy and Operating Reserve Markets. Exhibit 4-9 provides an Operating Reserve eligibility summary for Resources that are qualified to provide Operating Reserve.

Exhibit 4-9: Resource Eligibility Summary for Provision of Operating Reserve

Resource	Day-Ahead and Real-Time		
	Regulating Reserve	Spinning Reserve	Supplemental Reserve
Committed or on-line Generation Resources	✓	✓	✓
Committed or on-line Demand Response Resources - Type II	✓	✓	✓
Available External Asynchronous Resources	✓	✓	✓
Available off-line or uncommitted Quick-Start Resources			✓
Uncommitted Demand Response Resources - Type I		✓	✓

4.2.1.1 Regulation Qualified Resource Requirements

Any Resource that meets the following criteria will be considered a Regulation Qualified Resource and may submit Offers for Regulating Reserve for use in the Energy and Operating Reserve Markets. All Regulation Qualified Resources must:

- be registered as an Regulating Qualified Resource asset in the Midwest ISO Energy and Operating Reserve Markets;
- have the appropriate control equipment installed to be capable of providing Regulation Service;
- be capable of supplying Regulation Service in either the up or down direction within the Regulation Response Time (initially set at 5 minutes);
- be capable of supplying Regulation Service for a continuous duration of 60 minutes;
- be capable of automatically responding to and mitigating frequency deviations via a speed governor or similar device;
- be capable of receiving and responding to automatic control signals on a 4 second periodicity and must provide telemetered output data that can be scanned every 2 seconds;
- if an External Asynchronous Resource, maintain firm transmission service to the Midwest ISO border in an amount equal to the Hourly Emergency Maximum Limit of the External Asynchronous Resource;
- if an External Asynchronous Resource, use a Fixed Dynamic Interchange Schedule to transfer Energy into the Midwest ISO Balancing Authority Area; and
- if a DRR-Type II, be physically located within the Market Footprint.

4.2.1.1.1 Day-Ahead Resource Eligibility

Regulation Qualified Resources that are eligible to provide Regulation Service in the Day-Ahead Energy and Operating Reserve Market are:

- committed Generation Resources;
- committed Demand Response Resources-Type II; and
- available External Asynchronous Resources.

that have their hourly Regulation Qualified Resources availability flags set to “True”.

4.2.1.1.2 Real-Time Resource Eligibility

Regulation Qualified Resources that are eligible to provide Regulation Service in the Real-Time Energy and Operating Reserve Market are:

- synchronized Generation Resources;
- synchronized Demand Response Resources-Type II; and
- available External Asynchronous Resources.

that have their hourly Regulation Qualified Resource availability flags set to “True”.

4.2.1.2 Spin Qualified Resource Requirements

Any Regulation Qualified Resource is also a Spin Qualified Resources. Resources that meet the following criteria are considered Spin Qualified Resources and may submit Offers for Spinning Reserve for use in the Energy and Operating Reserve Markets. All Spin Qualified Resources must:

- be registered as an Spin Qualified Resource asset in the Midwest ISO Energy and Operating Reserve Markets;
- be capable of automatically responding to and mitigating frequency deviations if required by Applicable Reliability Standards;
- be capable of deploying 100% of their cleared Spinning Reserve (including any Spinning Reserve cleared to meet Supplemental Reserve Requirements) within the Contingency Reserve Deployment Period;
- be capable of deploying 100% of their cleared Spinning Reserve for a continuous duration of 60 minutes or the maximum duration specified by Applicable Reliability Standards;
- be capable of providing telemetered output data that can be scanned every 10 seconds (except for DRR-Type I which can provide 10 second metered output data as part of normal Metered data submission);
- if an External Asynchronous Resource, maintain firm transmission service to the Midwest ISO border in an amount equal to the Hourly Emergency Maximum limit of the External Asynchronous Resource;
- if an External Asynchronous Resource, use a Fixed Dynamic Interchange Schedule to transfer Energy into the Midwest ISO Balancing Authority Area; and

- if a DRR-Type I or DRR-Type II, be physically located within the Market Footprint.

4.2.1.2.1 Day-Ahead Resource Eligibility

Spin Qualified Resources that are eligible to provide Spinning Reserve in the Day-Ahead Energy and Operating Reserve Market are:

- committed Generation Resources;
- uncommitted Demand Response Resources-Type I;
- committed Demand Response Resources-Type II; and
- available External Asynchronous Resources,

that have their hourly Spin Qualified Resource availability flags set to “True”.

4.2.1.2.2 Real-Time Resource Eligibility

Spin Qualified Resources that are eligible to provide Spinning Reserve in the Real-Time Energy and Operating Reserve Market are:

- synchronized Generation Resources;
- uncommitted Demand Response Resources-Type I
- synchronized Demand Response Resources-Type II; and
- available External Asynchronous Resources,

that have their hourly Spin Qualified Resources availability flags set to “True”.

4.2.1.3 Supplemental Qualified Resource Requirements

Any Spin Qualified Resource is also a Supplemental Qualified Resource. The following requirements apply specifically to Resources that do not qualify as Spin Qualified Resources but are capable of providing Supplemental Reserve. All Supplemental Qualified Resources must:

- be registered as an Supplemental Qualified Resource asset in the Midwest ISO Energy and Operating Reserve Markets;
- have a Minimum Run Time (or Minimum Interruption Time for DRR-Type I) less than or equal to three hours if a Quick-Start Resource;

- be capable of deploying 100% of their cleared Supplemental Reserve within the Contingency Reserve Deployment Period;
- be capable of deploying 100% of their cleared Supplemental Reserve for a continuous duration of 60 minutes or the maximum duration specified by Applicable Reliability Standards;
- be capable of providing telemetered output data that can be scanned every 10 seconds (except for DRR-Type I which can provide 10 second metered output data as part of normal Metered data submission);
- if an External Asynchronous Resource, maintain firm transmission service to the Midwest ISO border in an amount equal to the Hourly Emergency Maximum limit of the External Asynchronous Resource;
- if an External Asynchronous Resource, use a Fixed Dynamic Interchange Schedule to transfer Energy into the Midwest ISO Balancing Authority Area; and
- if a DRR-Type I or DRR-Type II, be physically located within the Market Footprint.

4.2.1.3.1 Day-Ahead Resource Eligibility

Supplemental Qualified Resources that are not Spin Qualified Resources that are eligible to provide Supplemental Reserve in the Day-Ahead Energy and Operating Reserve Market are:

- uncommitted Quick-Start Resources;
- committed Generation Resources;
- uncommitted Demand Response Resources-Type I;
- committed Demand Response Resources-Type II; and
- available External Asynchronous Resources,

that have their hourly Supplemental Qualified Resource availability flags set to “True”.

4.2.1.3.2 Real-Time Resource Eligibility

Supplemental Qualified Resources that are not Spin Qualified Resources that are eligible to provide Supplemental Reserve in the Real-Time Energy and Operating Reserve Market are:

- uncommitted Quick-Start Resources;

- synchronized Generation Resources;
- uncommitted Demand Response Resources-Type I;
- synchronized Demand Response Resources-Type II; and
- available External Asynchronous Resources,

that have their hourly Supplemental Qualified Resource availability flags set to “True”.

4.2.2 Generation Resources and DRR-Type II Offer Requirements

The following Subsection describes the economic and operational Offer data for Generation Resources and Demand Response Resources-Type II and how these data are used in commitment and dispatch decisions.

4.2.2.1 Offer Information Summary

Generation Resource and DRR-Type II Offers consist of data submitted by MPs for consideration in commitment and dispatch activities. Such Offer data may be submitted for the Day-Ahead and Real-Time Energy and Operating Reserve Markets. Exhibits 4-10 and 4-10A identifies the data that may be included in a Generation Resource or DRR-Type II Offer and the markets in which they apply.

Exhibit 4-10: Generation Resource and DRR-Type II Economic Data Summary

Generation and DRR-Type II Offer Data	Units	Day-Ahead Offer	Real-Time Offer	Notes
Economic Offer Data				
Energy Offer Curve	MW, \$/MWh	Hourly	Hourly	
No-Load Offer	\$/hr	Hourly	Hourly	2
Regulating Reserve Offer	\$/MW	Hourly	Hourly	1
Spinning Reserve Offer	\$/MW	Hourly	Hourly	1
On-Line Supplemental Reserve Offer	\$/MW	Hourly	Hourly	1,3
Off-Line Supplemental Reserve Offer	\$/MW	Hourly	Hourly	4
Hot Start-Up Offer	\$	Daily	Daily	2
Intermediate Start-Up Offer	\$	Daily	Daily	2
Cold Start-Up Offer	\$	Daily	Daily	2
Self-Scheduled Regulation	MW	Hourly	Hourly	1
Self-Scheduled Spinning Reserve	MW	Hourly	Hourly	1
Self-Scheduled On-Line Supplemental Reserve	MW	Hourly	Hourly	1,3
Self-Schedule Off-Line Supplemental Reserve	MW	Hourly	Hourly	4
Self-Scheduled Energy	MW	Hourly	Hourly	
Note 1: If qualified Note 2: Default Offers are also submitted by MPs to restrict the values submitted for Energy and Operating Reserve Markets, also used if no values are submitted for Energy and Operating Reserve Markets. Note 3: If not Spin Qualified Note 4: Quick-Start Resources only.				

ERCOT Protocols
Section 6: Ancillary Services

January 1, 2007

6	<i>Ancillary Services.....</i>	<i>6-1</i>
6.1	Ancillary Services Required by ERCOT	6-1
6.2	Providers of Ancillary Services	6-5
6.3	Responsibilities of ERCOT and Qualified Scheduling Entities.....	6-5
6.4	Standards and Determination of the Control Area Requirements for Ancillary Services.....	6-8
6.5	Technical Requirements for Providers of Ancillary Services.....	6-10
6.6	Selection Methodology	6-41
6.7	Deployment Policy	6-48
6.8	Compensation for Services Provided.....	6-60
6.9	Settlement for ERCOT-Provided Ancillary Services	6-122
6.10	Ancillary Service Qualification, Testing and Performance Standards.....	6-138

6 ANCILLARY SERVICES

6.1 Ancillary Services Required by ERCOT

ERCOT shall be responsible for developing a daily Ancillary Services Plan with sufficient Ancillary Services (AS) to maintain the security and reliability of the ERCOT System consistent with ERCOT and North American Electric Reliability Council (NERC) standards. The Ancillary Services required by ERCOT are described below. ERCOT shall procure and deploy Ancillary Services on behalf of QSEs.

6.1.1 *Balancing Energy Service*

As provided by ERCOT to the Qualified Scheduling Entities (QSEs): Balancing Energy is deployed by ERCOT with the goals that (1) Regulation Service in either direction not be depleted during the interval, and (2) Regulation Service up and down energy is deployed in each Settlement Interval such that the net energy in regulation is minimized.

As provided by a QSE to ERCOT: The provision of incremental or decremental energy dispatched by Settlement Interval to meet the balancing needs of the ERCOT System.

6.1.2 *Regulation Service – Down*

As provided by ERCOT to the QSEs: Regulation-down power is deployed in response to an increase in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

As provided by a QSE to ERCOT: The provision of Generation Resource capacity to ERCOT so that ERCOT can deploy power for the purpose of controlling frequency by continuously balancing generation and Load within the ERCOT System.

[PRR307: Revise Section 6.1.2 as follows when system change implemented.]

As provided by a QSE to ERCOT: The provision of Resource capacity to ERCOT so that ERCOT can deploy power for the purpose of controlling frequency by continuously balancing generation and Load within the ERCOT System.

6.1.3 *Regulation Service-Up*

As provided by ERCOT to the QSEs: Regulation up power is deployed in response to a decrease in ERCOT System frequency to maintain the target ERCOT System frequency within predetermined limits according to the Operating Guides.

As provided by a QSE to ERCOT: The provision of Generation Resource capacity to ERCOT so that ERCOT can deploy power for the purpose of controlling frequency by continuously balancing generation and Load within the ERCOT System.

[PRR307: Revise Section 6.1.3 as follows when system change implemented.]

As provided by a QSE to ERCOT: The provision of Resource capacity to ERCOT so that ERCOT can deploy power for the purpose of controlling frequency by continuously balancing generation and Load within the ERCOT System.

6.1.4 *Responsive Reserve Service*

As provided by ERCOT to the QSEs: Operating reserves ERCOT maintains to restore the frequency of the ERCOT System within the first few minutes of an event that causes a significant deviation from the standard frequency. Furthermore, Responsive Reserve Service provides reserved Resources that are deployed for the Operating Hour in compliance with these Protocols in response to loss-of-Resource contingencies on the ERCOT System.

As provided by a QSE to ERCOT: The provision of capacity by unloaded Generation Resources that are on line, Resources controlled by high set under-frequency relays or from Direct Current (DC) tie response. The amount of capacity from unloaded Generation Resources or DC Tie response is limited to the amount allowed in the Operating Guides or that, which can be deployed within 15 seconds.

[PRR307: Revise Section 6.1.4 as follows when system change implemented.]

As provided by a QSE to ERCOT: The provision of capacity by unloaded Generation Resources that are on line, Load Resources capable of controllably reducing or increasing consumption under dispatch control (similar to AGC) and that immediately responding proportionally to frequency changes (similar to generator governor action), and Resources controlled by high set under-frequency relays or from Direct Current (DC) Tie response. The amount of capacity from unloaded Generation Resources or DC Tie response is limited to the amount allowed in the Operating Guides or that, which can be deployed within 15-seconds.

6.1.5 *Non-Spinning Reserve Service*

As provided by ERCOT to the QSEs: Reserves maintained by ERCOT, that are deployed for the Operating Hour in response to loss-of-Resource contingencies on the ERCOT System.

As provided by a QSE to ERCOT: Off-line Generation Resource capacity, or reserved capacity from On-line Generation Resources, capable of being ramped to a specified output level within thirty (30) minutes or Loads acting as a Resource that are capable of being interrupted within

thirty (30) minutes and that are capable of running (or being interrupted) at a specified output level for at least one (1) hour.

6.1.6 *Replacement Reserve Service*

As provided by ERCOT to the QSEs: The instruction, by ERCOT, for the deployment of Loads or non-synchronized Generation Resources in order to make available additional Balancing Energy Service.

As provided by a QSE to ERCOT: A Resource capable of providing additional Balancing Energy Service to ERCOT when deployed.

6.1.7 *Voltage Support*

As provided by ERCOT to the QSEs and the TDSPs: The coordinated scheduling of Voltage Profiles at transmission busses to maintain transmission voltages on the ERCOT System in accordance with Operating Guides.

As provided by a QSE to ERCOT: The provision of capacity from a Generation Resource required to provide VSS, whose power factor and output voltage level can be scheduled by ERCOT to maintain transmission voltages within acceptable limits throughout the ERCOT System in accordance with Operating Guides.

6.1.8 *Black Start Service*

As provided by ERCOT to QSEs: The procurement by ERCOT through Agreements, pursuant to emergency Dispatch by ERCOT and emergency restoration plans of Resources which are capable of self-starting or Resources within close proximity of another power pool which are capable of starting from such power pool via a firm standby power supply contract, without support from the ERCOT System, or transmission equipment in the ERCOT System in the event of a blackout, in order to begin restoration of the ERCOT System to a secure operating state. Resources which can be started with a minimum of pre-coordinated switching operations using ERCOT transmission equipment within the ERCOT System may be considered for Black Start Service only where switching may be accomplished within one (1) hour or less.

As provided by a Generator or a QSE to ERCOT: The provision of Resources under a Black Start Agreement, pursuant to emergency Dispatch, which are capable of self-starting or Resources within close proximity of another power pool which are capable of starting from such power pool via a firm standby power supply contract, without support from the ERCOT System, or transmission equipment in the ERCOT System in the event of a blackout. Resources which can be started with a minimum of pre-coordinated switching operations using ERCOT transmission equipment within the ERCOT System may be considered for Black Start Service only where switching may be accomplished within one (1) hour or less.

6.1.9 *Reliability Must-Run Service*

As provided by ERCOT to QSEs: Agreements for capacity and energy from Resources which otherwise would not operate and which are necessary to provide voltage support, stability or management of localized transmission constraints under first contingency criteria, as described in the Operating Guides. This includes service provided by RMR Units and MRA Resources.

As provided by a QSE to ERCOT: The provision of Generation Resource capacity and/or energy Resources under a Reliability Must-Run (RMR) Agreement or a Must Run Alternative (MRA) Agreement, including Agreements with Synchronous Condenser Units, whose operation is directed by ERCOT.

6.1.10 *Out of Merit Capacity Service*

As provided by ERCOT to QSEs: The provision by ERCOT of Out of Merit Order (OOM) Replacement Reserve Service from Generation Resources, that would otherwise not be selected to operate because of their place (or absence) in the Merit Order of Resources' bids for Ancillary Services. OOMC is used by ERCOT to provide for the availability of sufficient capacity so that Balancing Energy bids are available to solve capacity insufficiency, Congestion, or other reliability needs. Loads Acting as Resources will not be available to ERCOT to provide OOMC Service.

As provided by a QSE to ERCOT: Generation capable of providing additional Balancing Energy Service to ERCOT when deployed.

6.1.11 *Out-Of-Merit Energy Service*

As provided by ERCOT to QSEs: The deployment by ERCOT for the Settlement Interval of energy from Resources, that may or may not have provided Resource-specific premium bids, and used by ERCOT to provide Balancing Energy Service for resolving Congestion, the actuation for specific units under an ERCOT approved Special Protection System, or, if required, in declared emergencies as described in these Protocols.

As provided by a QSE to ERCOT: The provision of incremental or decremental energy dispatched from a specific Resource in emergency operations by Settlement Interval in Real Time to meet the balancing needs of the ERCOT System or in declared emergencies.

6.1.12 *Zonal Out-of-Merit Energy (Zonal OOME) Service*

As provided by ERCOT to QSEs: The deployment by ERCOT for the Settlement Interval of energy from a QSE's fleet of Resources, that may or may not have provided Resource-specific premium bids, and used by ERCOT when all other methods for resolving Congestion have failed or if required in declared emergencies as described in these Protocols.

As provided by a QSE to ERCOT: The provision of incremental or decremental energy Dispatched from a QSE's fleet of Resources in emergency operations by Settlement Interval in Real Time to meet the needs of the ERCOT System when all other methods for resolving Congestion have failed or in declared emergencies.

6.2 Providers of Ancillary Services

6.2.1 *Ancillary Services Provided Solely by ERCOT*

ERCOT is the sole provider of system-wide Balancing Energy Service; Generation Resource unit-specific Voltage Support Service (VSS), Black Start Service, Replacement Reserve Service, Zonal OOME Service, RMR Service, OOMC, and OOME Service to QSEs.

ERCOT will arrange Resources to provide system-wide VSS, Black Start, Zonal OOME, and RMR Service from QSEs. ERCOT will direct Resources to provide OOMC or OOME in accordance with OOMC Service and OOME Service provisions of these Protocols.

6.2.2 *Ancillary Services Provided in Part by ERCOT and in Part by Qualified Scheduling Entities*

Each QSE may self-arrange its Obligation assigned by ERCOT for each of the following Ancillary Services: Regulation Up, Regulation Down, Responsive Reserve, and Non-Spinning Reserve. Any of the Ancillary Services that are not self-arranged will be procured as a service by ERCOT on behalf of the QSEs.

6.3 Responsibilities of ERCOT and Qualified Scheduling Entities

6.3.1 *ERCOT Responsibilities*

- (1) ERCOT, through its Ancillary Services function, shall develop the Operating Day Ancillary Services Plan for the ERCOT System, and the Day Ahead Ancillary Service Obligation which will be assigned based on Load Ratio Share data, by LSE, aggregated to the QSE level. Unless otherwise provided in these Protocols, a QSE's allocation for Ancillary Service Obligation will be determined for each hour according to that LSE's Load Ratio Share computed by ERCOT. The LSE Ancillary Service allocation for the Day Ahead Ancillary Service Obligation shall be based on the hourly Load Ratio Share from the Initial Settlement data, for the Operating Day that is fourteen (14) days before the day in which the Obligation is being calculated, as defined in Section 9.2, Settlement Statements, for the same hour and day of the week multiplied by the quantity of the service in the Operating Day Ancillary Service Plan.

[PRR426: Replace Section 6.3.1, item (1) above with the following upon system

implementation:]

- (1) ERCOT, through its Ancillary Services function, shall develop the Operating Day Ancillary Service Plan for the ERCOT System. The Day Ahead Ancillary Service Obligation, except for Regulation Service, will be assigned based on Load Ratio Share data, by LSE, aggregated to the QSE level. The Day Ahead Regulation Service Obligation will be assigned based on Energy Ratio Share data, by LSE and Generation Resource, aggregated to the QSE level. Unless otherwise provided in these Protocols, a QSE's allocation for all Ancillary Service Obligations except Regulation Service will be determined for each hour according to that LSE's Load Ratio Share computation by ERCOT. For all Ancillary Services Obligations except Regulation Service, the LSE Ancillary Service allocation for the Day Ahead Ancillary Service Obligation shall be based on the hourly Load Ratio Share from the Initial Settlement data, for the Operating day that is fourteen (14) days before the day in which the Obligation is being calculated, as defined in Section 9.2, Settlement Statements, for the same hour and day of the week multiplied by the quantity of the service in the Operating Day AS Plan. For Regulation Service, the LSE plus the Generation Resource Ancillary Service allocation shall be the hourly Energy Ratio Share of the Load data and the data from Uncontrollable Renewable Resources electing to utilize Renewable Production Potential for URC and OOME from the Initial Statement, as defined in Section 9.2, Settlement Statements, for the same hour and day of the week multiplied by the quantity of the service in the Operating Day Ancillary Service Plan.
- (2) ERCOT shall procure required Ancillary Services not self-arranged by QSEs.
- (3) ERCOT accepts Ancillary Service bids only from QSEs.
- (4) ERCOT shall allow the same capacity to be bid as multiple Ancillary Services types recognizing that this capacity may only be selected for one service.
- (5) ERCOT shall ensure provision of Ancillary Services to all ERCOT System Market Participants in accordance with these Protocols.
- (6) ERCOT shall not discriminate when obtaining Ancillary Services from QSEs submitting Ancillary Service bids. ERCOT shall not discriminate between Self-Arranged Ancillary Services and ERCOT-procured Ancillary Services when dispatching Ancillary Services.
- (7) For AS that are not self-arranged, ERCOT shall procure any additional Resources ERCOT requires during the Day-Ahead Scheduling Process, the Adjustment Period process, or the Operating Period.
- (8) ERCOT shall procure Resources that are used to provide Reliability Must-Run Service or Black Start Service through longer-term Agreements.
- (9) Following submission of QSE self-arranged schedules, ERCOT will identify the remaining amount of Ancillary Services that must be acquired in order to complete

ERCOT's Day-Ahead Ancillary Services Plan. Regulation Up, Regulation Down, Responsive, and Non-Spinning services will be procured by ERCOT on the timeline described in Section 4, Scheduling.

- (10) ERCOT will not profit financially from the market. ERCOT will follow the Protocols with respect to the procurement of Ancillary Services and will not otherwise take actions regarding Ancillary Services with the intent to influence, set or control market prices.
- (11) ERCOT will provide that Market Clearing Prices are posted on the Market Information System (MIS) in a timely manner as stated in Section 12.4.1, Scheduling Information, of these Protocols. ERCOT will monitor Market Clearing Prices for errors and will "flag" for further review questionable prices before posting, and make adjustments or notations in the posting if there are conditions that cause the price to be questionable. ERCOT may only correct the price consistent with these Protocols.
- (12) ERCOT shall post the aggregated ERCOT AS Bid Stacks in accordance with Section 12.4.2, Ancillary Service Related Information of these Protocols.
- (13) ERCOT will, through procurement processes specified in these Protocols, procure Ancillary Services as required and charge QSEs for those Ancillary Services in accordance with these Protocols.
- (14) ERCOT will ensure ERCOT electric network reliability and adequacy and will afford the market a reasonable opportunity to supply reliability solutions.
- (15) ERCOT will not substitute one type of Ancillary Service for another.
- (17) ERCOT shall make reasonable efforts to minimize the use of OOMC, Zonal OOME, or contracted RMR Facilities. This includes entering into MRA Agreements with Resources selected through the planning process, pursuant to Section 6.5.9.2, to provide services to meet reliability requirements at lower total expected costs than would otherwise be provided by RMR Agreements.
- (18) ERCOT will provide timely information to those Resource units providing OOMC and RMR Services as to the specific use of each unit dispatched.

6.3.2 *Qualified Scheduling Entity Responsibilities*

- (1) Unless contracted otherwise, and with the exception of Balancing Energy decremental bids as described in Section 4, Scheduling, of these Protocols, Resources capable of providing Ancillary Services are not required to provide those Resources or to submit bids to ERCOT, provided, however, Resources shall honor bids submitted to ERCOT for Ancillary Services under these Protocols and shall, use reasonable efforts to provide Ancillary Services in accordance with applicable emergency procedures in these Protocols and in the Operating Guides.

- (2) Ancillary Service providers shall provide and deploy, as directed by ERCOT, the Ancillary Service(s) that they have agreed to provide.
- (3) QSEs may specify Self-Arranged Ancillary Services in accordance with the Day-Ahead Scheduling as described in Section 4.4, Day Ahead Scheduling Process.

[PIP106: Current design does not provide for DLC Profiles. When DLC Profiles are implemented add this item (4) to section 6.3.2]

- (4) QSEs that have Direct Load Control programs as described in Section 18.7.2, Load Profiling of ESI IDs Under Direct Load Control, will notify ERCOT immediately of any deployment of the program. This applies solely to QSEs using Load Profiling for Settlement.

6.4 Standards and Determination of the Control Area Requirements for Ancillary Services

6.4.1 Standards for Determining Ancillary Services Quantities

- (1) ERCOT shall comply with the requirements for determination of Ancillary Service quantities as specified in these Protocols and the Operating Guides.
- (2) ERCOT shall, at least annually, determine with supporting data, the methodology for determining the minimum quantity requirements for each Ancillary Service needed for reliability, including the percentage of Load acting as a Resource allowed to provide Responsive Reserve Service calculated on a monthly basis.
- (3) ERCOT shall initially determine the percentage of Load acting as a Resource on a calendar month basis for the remainder of the current year allowed to provide Responsive Reserve Service within ninety (90) days after implementation of this Protocol revision.
- (4) The ERCOT Board shall review and approve ERCOT's methodology for determining the minimum Ancillary Service requirements and the monthly percentage of Load acting as a Resource allowed to provide Responsive Reserve Service.
- (5) If ERCOT determines a need for additional Ancillary Service Resources pursuant to these Protocols or the Operating Guides, after an Ancillary Services Plan for a specified day has been posted, ERCOT will inform the market by posting on the Market Information System, of ERCOT's intent to procure additional Ancillary Service Resources in accordance with Section 4.5.8, ERCOT Notice to Procure Additional Ancillary Services. ERCOT will post the reliability reason for the increase in service requirements.
- (6) Once specified by ERCOT for an hourly interval, Ancillary Service quantity requirements may not be decreased.

- (7) ERCOT shall instruct such that sufficient Resource capacity is on line, in appropriate locations, and available to ERCOT to meet the potential needs of the ERCOT System.
- (8) ERCOT shall include in its AS plan sufficient capacity to automatically control frequency to meet NERC standards.
- (9) ERCOT will post Engineering Studies on the MIS representing specific Ancillary Service requirements as described in Section 12, ERCOT Market Information System.

6.4.2 *Determination of ERCOT Control Area Requirements*

By the twentieth (20th) day of the current month, ERCOT will post a forecast of minimum Ancillary Services quantity requirements for the next calendar month.

Prior to 0600 of the Day Ahead, ERCOT will use the Day Ahead Load forecast and will develop an Ancillary Services Plan that identifies the amount of Ancillary Services necessary for each hour of the next day as specified in Section 4, Scheduling. The amount of Ancillary Services required may vary depending on ERCOT System conditions from hour to hour.

By 0600 of the Day Ahead, ERCOT will post an ERCOT System and zonal Load forecast for the next seven (7) days, by hour. ERCOT will notify each QSE of its allocated share of Ancillary Services for each hour for the next day, as specified in Section 4, Scheduling. ERCOT will make available to Market Participants any ERCOT area Load forecasts used in the determination of its ERCOT System and zonal forecasts.

ERCOT will determine the total required amount of each Ancillary Service using the Operating Guides and the following:

- (1) **Balancing Energy Service:** ERCOT will estimate Balancing Energy needs based on the actual Load, the difference in forecasted Loads and Loads reported in bilateral schedules, deployed Regulation Service, and forecasted Congestion.
- (2) **Regulation Service:** ERCOT will use its operational judgment and experience to determine the quantity of Regulation Up Service and Regulation Down Service procured. The quantity of Regulation Up Service may differ from the quantity of Regulation Down Service in any particular hour.
- (3) **Responsive Reserve Service:** The requirement for Responsive Reserve Service is specified in the Operating Guides. Using ERCOT-approved procedures ERCOT may increase the quantity requirement based on its judgment of reliability conditions.
- (4) **Non-Spinning Reserve Service:** ERCOT will use its operational judgment and experience to determine the quantity of Non-Spinning Reserve Service procured.
- (5) **Replacement Reserve Service:** Replacement Reserve Service is procured from Generation Resource units planned to be Off-line and LaaRs that are available for interruption during the period of requirement. The QSE for a procured RPRS Resource

must additionally make available to ERCOT via Balancing Energy Service bid(s) (i) for a Generation Resource, a quantity greater or equal to the High Sustainable Limit (if unavailable, the High Operating Limit) minus the Low Sustainable Limit (if unavailable, the Low Operating Limit) of the Generation Resource receiving the RPRS Dispatch Instruction in the Congestion Zone of the Generation Resource, and (ii) for a LaaR, a quantity equal to the amount of procured capacity from the LaaR in the Congestion Zone of the LaaR. ERCOT will consider the Generation Resource capacity On-line, based on Resource Plans, in its determination of Zonal Congestion and Local Congestion requirements. ERCOT will evaluate the need for Replacement Reserve Service necessary to correct for ERCOT total capacity insufficiency, Zonal Congestion, or Local Congestion. ERCOT shall determine the amount of RPRS to provide sufficient capacity in appropriate locations to provide ERCOT System security as specified in the Operating Guides, given ERCOT forecasted Load conditions as posted on the Market Information System.

- (6) **Voltage Support:** ERCOT in coordination with the TDSPs shall conduct studies to determine the normally desired Voltage Profile for all Voltage Support busses in the ERCOT System and shall post all Voltage Profiles on the Market Information System. ERCOT may temporarily modify its requirements based on Current System Conditions. ERCOT shall determine the amount of Voltage Support Service needed to provide sufficient reactive capacity in appropriate locations to provide ERCOT System security as specified in the Operating Guides.
- (7) **Black Start Service:** ERCOT shall periodically determine and review the location and number of Black Start Resources required, as well as any special transmission or voice communication needs required. ERCOT and providers of this service shall meet the requirements as specified in the Operating Guides and in NERC policy.

6.5 Technical Requirements for Providers of Ancillary Services

Providers of Ancillary Services shall meet the general requirements specified in the subsection 6.5.1, General Technical Requirements below as well as the requirements of the specific Ancillary Service being provided, as described in Sections 6.5.2, Balancing Energy Service through 6.5.11, Zonal Out-of-Merit Energy Service.

6.5.1 General Technical Requirements

Providers of Ancillary Services shall meet the following general requirements.

6.5.1.1 Requirement for Operating Period Data for System Reliability and Ancillary Service Provision

Operating Period data will be used by ERCOT to monitor the reliability of the ERCOT System in Real Time, monitor compliance with Ancillary Service Obligations, perform historical analysis, and predict the short-term reliability of the ERCOT System using network analysis software.

Each TDSP, at its own expense, may obtain such Operating Period data from ERCOT or from QSEs.

- (1) A QSE representing a Generation Entity that has Generation Resources connected to a TDSP shall provide the following Real Time data to ERCOT for each individual generating unit at a Generation Resource plant location and ERCOT will make the data available to the Generation Resource's host TDSP (at TDSP expense):
 - (a) gross or net real power;
 - (b) gross or net Reactive Power;
 - (c) if gross quantities are provided, the plant auxiliary Load data will also be supplied;
 - (d) status of switching devices in the plant switchyard not monitored by the TDSP affecting flows on the ERCOT System;
 - (e) Frequency Bias of Portfolio Generation Resources under QSE operation;
 - (f) any data mutually agreed by ERCOT and the QSE to adequately manage system reliability and monitor Ancillary Service Obligations;
 - (g) generator breaker status;
 - (h) High Operating Limit; and
 - (i) Low Operating Limit.

[PRR590: Add items (j) and (k) upon system implementation:]

- (j) AGC status; and
- (k) ramp rate.

[PRR307: Revise Section 6.5.1.1(1) and 6.5.1.1(1) (c) & (g) as follows when system change implemented.]

- (1) A QSE representing a Generation Entity or a Competitive Retailer that has Resources connected to a TDSP shall provide the following Real Time data to ERCOT for each individual generating unit or LaaR capable of controllably reducing or increasing consumption under Dispatch control (similar to AGC) and that immediately respond proportionally to frequency changes (similar to generator governor action) at a Resource plant location and ERCOT will make the data available to the Resource's host TDSP (at TDSP expense):

- (c) If gross quantities are provided, the plant auxiliary Load data will also be supplied as needed to determine the net output;
- (g) Resource breaker status;

[PRR590: Add paragraph (2) and renumber subsequent paragraphs upon system implementation:]

- (2) A QSE representing Uncontrollable Renewable Resources is exempt from the requirements of Section 6.5.1.1(1)(j) and (k).
- (2) Any QSE providing Responsive Reserve and/or Regulation must provide for communications equipment to receive ERCOT telemetered control deployments of service power.
- (3) Any QSE providing Regulation Service must provide appropriate Real Time feedback signals to report the control actions allocated to the QSEs Generation Resources.
- (4) Any QSE that represents a provider of Responsive Reserve, Non-Spinning Reserve, or Replacement Reserve using LaaR shall provide separate telemetry of the real power consumption of each LaaR providing the above Ancillary Services, the LaaR response to Dispatch Instructions for each LaaR, and the status of the breaker controlling that LaaR. If LaaR is used as a Responsive Reserve Resource, the status of the high-set under frequency relay will also be telemetered.

[PRR307: Revise Section 6.5.1.1(3) and 6.5.1.1(4) as follows when system change implemented.]

- (3) Any QSE providing Regulation Service must provide appropriate Real Time feedback signals to report the control actions allocated to the QSEs Resources.
- (4) Any QSE that represents a provider of Responsive Reserve, Non-Spinning Reserve, or Replacement Reserve using interruptible Load as a Resource shall provide separate telemetry of the real power consumption of each interruptible Load providing the above Ancillary Services, the LaaR response to Dispatch Instructions for each LaaR, and the status of the breaker controlling that interruptible Load. If interruptible Load is used as a Responsive Reserve Resource, the status of the high-set under frequency relay will also be telemetered.
- (5) Any QSE that represents a qualified provider of Balancing Up Load (BUL) need not provide telemetry but rather shall provide an estimate in Real Time representing the real power interrupted in response to the deployment of Balancing Up Load.

- (6) Real Time data for reliability purposes must be accurate to within three percent (3%). This telemetry may be provided from relaying accuracy instrumentation transformers.

[PRR590: Add paragraph (7) upon system implementation:]

- (7) A QSE representing a combined cycle plant may aggregate the AGC and ramp rate SCADA points for the individual units at a plant location into two distinct SCADA points (AGC and ramp rate) if the plant is configured to operate as such, i.e. gas turbine(s) and steam turbine(s) are controlled in aggregate from an AGC perspective.

6.5.2 Balancing Energy Service

The Balancing Energy Service bids shall consist of Balancing Energy Service Up, Balancing Energy Service Down, and Balancing Up Load bids. All Balancing Energy Service provider bids must be entered by the close of the Adjustment Period for the effective Operating Hour and shall become an Obligation at the close of the Adjustment Period. However, Balancing Energy Service provider bids may be withdrawn at any time prior to the close of the Adjustment Period. The portion of a QSE's Balancing Energy Service Up bid deployable in one interval that may be provided by off-line Generation Resources shall be limited to no more than the aggregate of qualified output amounts from Quick Start Units which have been demonstrated via the qualification testing process described in the Operating Guides. The QSE may utilize any remaining capacity from Quick Start Units in subsequent intervals once the Quick Start Units are On-line.

Balancing Energy Service bids shall be no greater than \$1,000 per MWh and no less than -\$1,000 per MWh for all Resources. Any Balancing Energy Service bids greater than \$1,000 per MWh or less than -\$1,000 per MWh will be rejected by ERCOT.

- (1) Balancing Energy Service bids must specify Congestion Zone, the type of bid, either a Resource or a BUL used to deploy the service, a ramp rate and service time period.

[PRR675: Replace the above language with the following upon system implementation:]

- (1) Balancing Energy Service bids must specify Congestion Zone, the type of bid, either a Resource or a BUL used to deploy the service, a ramp rate or ramp rate curve, and service time period.
- (a) For Balancing Energy Service Up and Balancing Energy Service Down, the bid curve consists of monotonically increasing ordered pairs of dollars per megawatt hour and cumulative megawatts (\$/MWh, MW).
 - (b) For Balancing Up Load, the bids consist of blocks in dollars per megawatt hour and megawatts (\$/MWh, MW). If the full block cannot be deployed the bid will be bypassed.

telemetered control deployments of power from ERCOT.

- (3) QSEs must demonstrate to ERCOT that they have the capability to switch control to constant frequency operation as specified in the Operating Guides using telemetry at the QSE's control center. ERCOT authorized operations of the QSEs regulation control system on constant frequency will be considered a Dispatch Instruction to deviate from schedule energy.
- (4) QSEs providing RGS will be required to provide a feedback signal meeting the requirements of ERCOT.
- (5) The Resource providing RGS must be capable of delivering the full amount of regulating capacity offered to ERCOT within ten (10) minutes.
- (6) Load Resources providing RGS must be capable of controllably reducing or increasing consumption under Dispatch control (similar to AGC) and immediately responding proportionally to frequency changes (similar to generator governor action).
- (7) The minimum amount of RGS that may be offered to ERCOT is one (1) MW.
- (8) QSE's bids will be in accordance with Section 4, Scheduling.
- (9) Regulation instructions will be included in a QSEs SCE calculation as instructed deviations.
- (10) Each Resource providing RGS must meet additional technical requirements specified in Section 6.10 Ancillary Service Qualification, Testing and Performance Standards of these Protocols.
- (11) Resources providing RGS must have their governors or automatic systems changing Load responding to frequency in service.
- (12) RGS is deployed proportionately to all providers.
- (13) Resources providing RGS must have sufficient qualified Generation Resources that will be online and able to respond in the Operating Hour for which they have been selected to provide the Ancillary Service.

6.5.4 *Responsive Reserve Service*

- (1) Responsive Reserve Service (RRS) may be provided by: (a) unloaded Generation Resources that are On-line, (b) Resources controlled by high-set under-frequency relays, (c) hydro Responsive Reserves, or (d) from DC Tie response that stops frequency decay. The minimum amount of RRS provided by Generation Resources shall be as specified in the Operating Guides. QSE's Generation Resources providing RRS must be On-line and capable of ramping to the awarded output level within ten (10) minutes of the notice to

deploy energy, must be immediately responsive to system frequency, and must be able to maintain the scheduled level for the period of service commitment. The amount of RRS on an individual Generation Resource may be further limited by requirements of the Operating Guides.

- (2) A QSE's Load acting as a Resource must be loaded and capable of unloading the scheduled amount of RRS within ten (10) minutes of instruction by ERCOT and by action of under-frequency relays as specified by the Operating Guides.
- (3) Any QSE providing RRS must provide communications equipment to receive ERCOT telemetered control deployments of power.
- (4) Generation Resources providing RRS must have their governors in service.
- (5) Loads acting as a Resource providing RRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay.
- (6) The minimum amount of RRS that may be offered to ERCOT is one (1) MW.
- (7) QSEs that provide the Resource for Responsive Reserve Service must ensure that Resources providing the service must be able to respond in the Operating Hour for which they have been selected to provide the RRS. Each Generation Resource and Load acting as a Resource and providing RRS must meet additional technical requirements specified in Section 6.10, Ancillary Service Qualification, Testing, and Performance Standards of these Protocols.
- (8) The amount of Resources on high-set under-frequency relays providing RRS will be limited to fifty percent (50 %) of the total ERCOT RRS requirement. ERCOT may reduce this limit if it believes that this amount will have a negative impact on reliability or if this limit would require additional Regulation to be deployed as prescribed in Section 6.4.1, Standards for Determining Ancillary Services Quantities.
- (9) The amount of RRS that a QSE can self-arrange using Load acting as a Resource is limited to the lower of: (1) the fifty percent (50%) limit set by these Protocols, or, (2) the limit established by ERCOT. However, a QSE may bid additional Load acting as a Resource above the percentage limitation established by ERCOT for sale of RRS to other Market Participants. The total amount of Responsive Reserve Service using Load acting as a Resource procured by ERCOT is also limited to the lesser of the fifty percent (50%) limit or the limit established by ERCOT.
- (10) QSE bids for RRS will be in accordance with Section 4, Scheduling.
- (11) A Load acting as a Resource has the option to request a Load bid to be deployed only as a complete block. To the extent that ERCOT deploys a bid by a Load acting as a Resource that has chosen a block deployment option, ERCOT shall either deploy the entire bid or, if only partial deployment is possible, skip the bid by the Load acting as a Resource and proceed to deploy the next available bid.

- (12) The amount of RRS that a QSE can self-arrange using Load acting as a Resource is limited to the percentage amount of total RRS that the LaaR can provide as specified by ERCOT. However, a QSE may bid additional Load acting as a Resource into the ERCOT RRS Ancillary Service market.
- (13) LaaRs providing the RRS requested shall return to their committed operating level for providing RRS as soon as practical considering process constraints. For LaaRs unable to return to their committed operating level within three (3) hours, their QSE may schedule the quantity of deficient Responsive Reserve Service Capacity from other uncommitted Generation or LaaR Resource(s) to fulfill their RRS obligation.
- (14) RRS bids from QSEs may include contributions from combined cycle Resources in Aggregated Units meeting the criteria in Section 6.8.2.4, Aggregating Units. Thus, to determine if a combined cycle Aggregated Unit is capable of performing its RRS Obligation, all Resources On-line in the Aggregated Unit will be measured as on an aggregate capacity basis and will be calculated from the lower of the High Sustainable Limits specified in the Resource Plan or through telemetry, or the seasonal tested Net Dependable Capability.

[PRR307: Revise Section 6.5.4(1), (2) & (5) as follows when system change implemented.]

6.5.4 Responsive Reserve Service

- (1) Responsive Reserve Service (RRS) may be provided by: (a) unloaded Generation Resources that are On-line, (b) Resources controlled by high-set under-frequency relays, (c) hydro Responsive Reserves, (d) from DC Tie response that stops frequency decay or, (e) from Load Resources capable of controllably reducing or increasing consumption under Dispatch control (similar to AGC) and that immediately respond proportionally to frequency changes (similar to generator governor action).

The minimum amount of RRS provided by Generation Resources and Load Resources capable of controllably reducing or increasing consumption under Dispatch control (similar to AGC) and that immediately respond proportionally to frequency changes (similar to generator governor action) shall be as specified in the Operating Guides. QSE's Resources providing RRS must be On-line and capable of ramping to the awarded output level within ten (10) minutes of the notice to deploy energy, must be immediately responsive to system frequency, and must be able to maintain the scheduled level for the period of service commitment. The amount of RRS on an individual Generation Resource may be further limited by requirements of the Operating Guides.

- (2) A QSE's Load acting as a Resource must be loaded and capable of unloading the scheduled amount of RRS within ten (10) minutes of instruction by ERCOT and must either be immediately responsive to system frequency or be interrupted by action of under-frequency relays as specified by the Operating Guides.

- (5) Interruptible Loads acting as a Resource providing RRS must provide a telemetered output signal, including breaker status and status of the under-frequency relay.

6.5.5 Non-Spinning Reserve Service (NSRS)

- (1) NSRS providers must be capable of being synchronized and ramped to their bid-specified output level within thirty (30) minutes. NSRS can be provided from unloaded On-line capacity that can ramp within thirty (30) minutes or Load acting as a Resource that is capable of unloading within thirty (30) minutes and that is not fulfilling any other commitment from the capacity, including participation in ERCOT markets, self-generation, or other energy transactions.
- (2) Loads providing NSRS must provide a telemetered output signal, including breaker status.
- (3) The minimum amount of NSRS that may be offered to ERCOT is one (1) MW.
- (4) Each Generation Resource and Load acting as a Resource and providing NSRS must meet additional technical requirements specified in Section 6.10, Ancillary Service Qualification Testing and Performance.
- (5) QSEs using Loads to provide NSRS must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resource to provide NSRS.
- (6) Resources providing NSRS must be able to respond in the hours for which they have been scheduled to provide the Ancillary Service.
- (7) QSE bids for NSRS will be submitted in accordance with Section 4, Scheduling.

6.5.6 Replacement Reserve Service

- (1) Replacement Reserve Service (RPRS) is provided by Resources that may otherwise be unavailable to ERCOT in the hours that ERCOT requests RPRS. These Resources may include Generation Resources that are expected to be off-line in the requested hours and Loads acting as a Resource that otherwise may be unavailable to be dispatched by ERCOT, i.e. Loads not declared as an active Resource in the Resource Plan at the time of the RPRS procurement.

[PRR307: Revise Section 6.5.6(1) as follows when system change implemented.]

6.5.6 Replacement Reserve Service

- (1) Replacement Reserve Service (RPRS) is provided by Resources that may otherwise be unavailable to ERCOT in the hours that ERCOT requests RPRS. These Resources may

include Generation Resources that are expected to be off-line in the requested hours and Loads acting as a Resource that are declared to be available in the Resource Plan but are not committed to any service Obligation.

- (2) Resources providing RPRS must provide a telemetered output signal, including breaker status.
- (3) The minimum amount of RPRS that may be offered to ERCOT is one (1) MW.
- (4) Resources eligible to bid must meet additional technical requirements specified in Operating Guides
- (5) There may only be one RPRS bid from any given Resource.
- (6) Generation Resource and Loads acting as a Resource accepted for RPRS must be able to respond in the hours for which they have been selected to provide the Ancillary Service.
- (7) QSEs using Loads to provide RPRS must be capable of responding to ERCOT Dispatch Instructions in a similar manner to QSEs using Generation Resources to provide RPRS.
- (8) Each Generation Resource and Load acting as a Resource providing RPRS must meet additional technical requirements specified in the Ancillary Service Qualification, Testing and Performance Standards, 6.10. QSEs must comply with their Balanced Schedule despite any generation provided by the RPRS unit. For example, the QSE supplying RPRS must adjust other Resources to accommodate the minimum operating output of the RPRS Resource selected by ERCOT in order to comply with their Balanced Schedule and Dispatch Instructions.
- (9) QSE bids for RPRS will be in accordance with Section 4, Scheduling.
- (10) RPRS may not be self-arranged by the QSE.
- (11) For RPRS procurements due to Local Congestion, on or before the second (2nd) Business Day after each Operating Day, ERCOT will post on the MIS, for such Operating Day:
 - (a) Each Resource receiving an RPRS Dispatch Instruction;
 - (b) Intervals for which each Resource received an RPRS Dispatch Instruction;
 - (c) The Low Sustainable Limit for each Resource receiving an RPRS Dispatch Instruction; and
 - (d) The binding transmission constraint (contingency and/or overloaded element(s)) causing the RPRS deployment.
- (12) For RPRS procurements due to Zonal Congestion, on or before the second (2nd) Business Day after each Operating Day, ERCOT will post on the MIS, for such Operating Day:

- (a) The amount of RPRS procured by zone; and
 - (b) The Market Clearing Price for Capacity (MCPC) by zone.
- (13) On or before the second (2nd) Business Day after each Operating Day, ERCOT will post on the MIS, for such Operating Day, the total amount of RPRS procured by hour for;
 - (a) Local Congestion;
 - (b) Zonal Congestion; and
 - (c) System capacity.

6.5.7 Voltage Support Service

All Generation Resources (including self-serve generating units) that have a gross generating unit rating greater than twenty (20) MVA or those units connected to the same transmission bus that have gross generating unit ratings aggregating to greater than twenty (20) MVA, that supply power to the ERCOT Transmission Grid, shall provide Voltage Support Service.

6.5.7.1 Generation Resources Required to Provide VSS Installed Reactive Capability

- (1) Generation Resources required to provide VSS must be capable of producing a defined quantity of Reactive Power at rated capability (MW) to maintain a Voltage Profile established by ERCOT. This quantity of Reactive Power is the Unit Reactive Limit (URL).
- (2) Generation Resources required to provide VSS except as noted below in items (3) or (4), shall have and maintain a URL which has an over-excited (lagging) power factor capability of ninety-five hundredths (0.95) or less and an under-excited (leading) power factor capability of ninety-five hundredths (0.95) or less, both determined at the generating unit's maximum net power to be supplied to the transmission grid and at the transmission system Voltage Profile established by ERCOT, and both measured at the point of interconnection to the TDSP.
- (3) Qualified renewable Generation Resources (as described in Section 14, Renewable Energy Credit Trading Program) in operation before February 17, 2004, required to provide VSS and all other Generation Resources required to provide VSS that were in operation prior to September 1, 1999, whose current design does not allow them to meet the URL as stated above, will be required to maintain a URL that is limited to the quantity of Reactive Power that the Generation Resource can produce at its rated capability (MW) as determined using procedures and criteria as described in the Operating Guides.
- (4) New generating units connected before May 17, 2005, whose owners demonstrate to ERCOT's satisfaction that design and/or equipment procurement decisions were made

appropriate signal representing some amount of Load to be qualified to provide BUL Resources. Once ERCOT has verified that it has received an appropriate Load reduction signal from the QSE and has successfully completed the BUL registration process, the QSE will be qualified to provide BUL Resources. Any changes to the BUL portfolio will require subsequent updates to the registration process. For NOIEs representing specific Loads qualified as BULs that are located behind the NOIE Settlement Meter points, the NOIE shall provide an alternative unique descriptor of the qualified BUL Load for ERCOT's records.

Generation Resources and Loads acting as Resources shall be evaluated at least annually by ERCOT for:

- (1) Correct operation of telemetry of the breakers controlling the Resource;
- (2) Correct mapping of QSE-provided telemetry of Ancillary Service energy to the appropriate energy Settlement Meter;
- (3) Data rate update requirements; and
- (4) Any other required telemetry attributes.

All Generation Resources and Loads acting as a Resource shall meet all requirements specified in the Operating Guides for proper response to system frequency. ERCOT may reduce the amount a Resource may contribute toward Ancillary Services if it finds unsatisfactory performance of the Resource as defined in these Protocols and the Operating Guides.

Qualification of a Resource, including a Load acting as a Resource, shall remain valid for such Resource in the event of a change of QSE for the Resource, provided that the new QSE demonstrates to ERCOT's reasonable satisfaction that the new QSE has adequate communications and control capability for the Resource.

6.10.3 *Ancillary Services Qualification Criteria and Portfolio Test Methods*

Only QSEs that have been qualified and tested may be used to provide Ancillary Services. ERCOT shall develop and operate its qualification and testing program to meet the following requirements for each Ancillary Service.

A QSE shall be qualified and tested to provide Service prior to initial operation and every five years thereafter.

A QSE may request a test for re-qualification at any time, but no later than the expiration of its current Ancillary Service qualification, and no more frequently than once every twelve (12) months. At the time of a request by a QSE for re-qualification, ERCOT may approve the re-qualification based on the AS performance metrics using the following criteria:

- (1) For Balancing Energy and RGS, the QSE's SCE Monitoring Criteria performance scores in Section 6.10.5.3, SCE Monitoring Criteria, were passing for five (5) out of the previous six (6) months.

- (2) For RRS, the RRS criteria in Section 6.10.5.4, Responsive Reserve Service Deployment Performance Monitoring Criteria, were passing for five (5) out of the previous six (6) performance intervals.
- (3) For NSRS, the NSRS monitoring criteria in Section 6.10.5.5, Non-Spinning Reserve Service Deployment Performance Monitoring Criteria, were passing for five (5) out of the previous six (6) deployment measurements without retest.

If the QSE passes the criteria, the QSE will be exempt from re-qualification testing for five (5) years from the date of the exemption request. ERCOT shall provide monthly performance updates to the QSE for the above criteria.

ERCOT is authorized to call up to two unannounced, unscheduled qualification tests after presenting to the QSE supporting information of an indication that a Resource may not be able to meet its stated Net Dependable Capability during any calendar year.

QSEs may qualify by using either Generation Resource(s) or Load(s) Acting as a Resource (LaaR(s)). If a QSE qualifies by using only a LaaR then the QSE may only provide Ancillary Services using LaaRs and will not be qualified to provide Ancillary Services using Generation Resources. However, if a QSE successfully completes the qualification using Generation Resource(s), that QSE will be qualified to provide Ancillary Services from both Generation Resources and LaaRs.

ERCOT may grant a “Provisional Qualification,” for a period not to exceed ninety (90) days, to a QSE that has performed an Ancillary Service qualification test (or tests) in good faith but failed to qualify due to problems that, in the sole discretion of ERCOT, are determined to be non-critical for the purpose of providing one or more Ancillary Services. Notwithstanding the failure of a QSE with Provisional Qualification to meet the applicable Ancillary Service criteria, such QSE may provide such Ancillary Service to the extent permitted by the terms of the Provisional Qualification.

6.10.3.1 Regulation

- (1) A regulation qualification test is conducted during a continuous sixty (60) minute period agreed on in advance by the QSE and ERCOT. QSEs may be qualified to provide Regulation Up or Regulation Down, or both, in separate testing.
- (2) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice communication circuits in order to validate the voice circuits.
- (3) For the sixty (60) minute duration of the test, when market and reliability conditions allow, the ERCOT Control Area Operator shall send a random sequence of raise, hold, and lower control signals to the QSE. To facilitate accurate measurements, each signal (raise, lower, or hold) shall remain unchanged for at least two (2) minutes. The control signals shall not request QSE portfolio performance beyond the stated high limit, low limit, and ramp rate limit agreed on prior to the test. During the test, one ten (10) minute period will test the QSE’s ability to achieve the entire amount of Regulation Up requested

for qualification during the period. One ten (10) minute period will test the QSE's ability to achieve the entire amount of Regulation Down requested for qualification during the period. To facilitate testing of large portfolios, ERCOT may test maximum ramp capability on subsets of Generation Resources in a portfolio.

- (4) The QSE's portfolio average real power output for each clock minute will be measured and recorded. The regulation test shall be conducted when all other schedules are held constant so that any real power increase or decrease is the result of the regulation requirement. The correlation coefficient between the expected average power from one minute to the next [limited to no more than the initial value + (request \times 1/2 \times stated ramp rate)], and the actual measured real power output during those minutes shall be statistically significant to two (2) positive standard deviations in order to pass the test.
- (5) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing RGRS and shall provide a copy of the certificate to the QSE.

6.10.3.2 Responsive Reserve Qualification Testing Criteria

- (1) Testing using Generation Resource(s)
 - (a) A test for RRS shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.
 - (b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.
 - (c) At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the QSE, ERCOT shall send a signal to the QSE requesting it to provide an amount of RRS. The QSE shall acknowledge the start of the test.
 - (d) For the thirty (30) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for: (i) the clock-minute prior to the instructions being received from ERCOT; (ii) the clock-minute following receipt of instructions from ERCOT and continuing for ten (10) minutes; and (iii) for each of the subsequent nineteen (19) clock-minutes. All measurements shall confirm the additional delivery of energy due to the deployment of Responsive Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount requested by ERCOT. Satisfactory performance shall be deemed acceptable if ninety percent (90%) of each clock-minute measurement ten (10) minutes after notice through the balance of the test period is equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount expected.
 - (e) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing RRS and shall provide a copy of the certificate to the QSE.

(2) Testing using Load(s) Acting as a Resource

- (a) A test for RRS shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.
- (b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.
- (c) At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the QSE, ERCOT shall send a signal to the QSE requesting it to provide an amount of RRS. The QSE shall acknowledge the start of the test.
- (d) Upon ERCOT issuing a verbal instruction to the QSE to deploy the LaaR, the QSE shall demonstrate that it has procedures in place to satisfy a satisfactory deployment of the LaaR(s) providing Responsive Reserve Service as required in Step 2 of an EECp, Section 5.6.7, EECp Steps. All measurements shall confirm the additional delivery of energy due to the deployment of Responsive Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred and fifty percent (150%) of the amount requested by ERCOT. A deployment will be deemed acceptable when ERCOT confirms the interruption of the Load(s) within ten (10) minutes of issuance of the instruction by ERCOT.
- (e) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing RRS from LaaRs and shall provide a copy of the certificate to the QSE designating its qualification to provide RRS from LaaRs.

6.10.3.3 Non-Spinning Reserve Qualification Testing Criteria

(1) Testing using Generation Resource(s)

- (a) A test for Non-Spinning Reserve Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.
- (b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.
- (c) At any time during the window, selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE, ERCOT shall notify the QSE using ERCOT's Messaging System requesting it to provide an amount of Non-Spinning Reserve the QSE wishes to be qualified to. The QSE shall acknowledge the start of the test.
- (d) For the sixty (60) minute duration of the test, the QSE output shall be measured as clock-minute average outputs for: (i) the clock-minute prior to the instructions being received from ERCOT; (ii) the clock-minute following receipt of instructions from ERCOT and continuing for thirty (30) minutes; and (iii) for each

of the subsequent twenty-nine (29) clock minutes. All measurements shall confirm the additional delivery of energy due to the deployment of Non-Spinning Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred five percent (105%) of the amount requested by ERCOT.

- (e) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing Non-Spinning Reserve and shall provide a copy of the certificate to the QSE.

(2) Testing using Load(s) Acting as a Resource

- (a) A test for Non-Spinning Reserve Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.
- (b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.
- (c) At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the QSE, ERCOT shall notify the QSE using ERCOT's Messaging System requesting the QSE provide the amount of Non-Spinning Reserve the QSE wishes to be qualified to provide. The QSE shall acknowledge the start of the test.
- (d) Upon ERCOT issuing a verbal instruction to QSE to deploy the LaaR, the QSE shall demonstrate that it has procedures in place to satisfactorily deploy LaaR(s) providing Non-Spinning Reserve Service. All measurements shall confirm the additional delivery of energy due to the deployment of Non-Spinning Reserve Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred and fifty percent (150%) of the amount requested by ERCOT. A deployment will be deemed acceptable when ERCOT confirms the interruption of the Load(s) within thirty (30) minutes of issuance of the instruction by ERCOT.
- (e) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing Non-Spinning Reserve from LaaRs and shall provide a copy of the certificate to the QSE designating its qualification to provide Non-Spinning Reserve from LaaRs.

6.10.3.4 Balancing Energy

(1) Testing using Generation Resource(s)

- (a) A test for Balancing Energy Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.
- (b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.

- (c) At any time during the window, selected by ERCOT when market and reliability conditions allow and not previously disclosed to the QSE, ERCOT shall notify the QSE using ERCOT's Messaging System requesting it to provide an amount of Balancing Energy. The QSE shall acknowledge the start of the test. During the sixty (60) minute duration of the test, within the limits of requested qualification, ERCOT will vary the amount of Balancing Energy requested.
 - (d) A QSE may qualify to provide only Balancing Energy Down Service using only Uncontrollable Renewable Resources by providing Balancing Energy Down Service, within the limits of requested qualification, in an amount available from the Uncontrollable Renewable Resource's Resource Plan at the time of the Dispatch Instruction. All measurements shall confirm the reduced delivery of energy due to the deployment of Balancing Down Energy Service when the generation amount of the Uncontrollable Renewable Resource is less than or equal to the Uncontrollable Renewable Resource's Resource Plan, less the amount requested by ERCOT.
 - (e) On successful demonstration of all test criteria, ERCOT shall qualify the QSE is capable of providing Balancing Energy and shall provide a copy of the certificate to the QSE.
- (2) Testing using Load(s) Acting as a Resource
- (a) A test for Balancing Energy Service shall be performed during a continuous eight (8) hour window agreed on by the QSE and ERCOT.
 - (b) ERCOT shall confirm the date and time of the test with the QSE using both the primary and alternate voice circuits to validate the voice circuits.
 - (c) At any time during the window, selected by ERCOT when market and reliability conditions allow, and not previously disclosed to the QSE, ERCOT shall notify the QSE using ERCOT's Messaging System requesting it to provide an amount of Balancing Energy. The QSE shall acknowledge the start of the test.
 - (d) Upon ERCOT issuing a verbal instruction to QSE to deploy the LaaR, the QSE shall demonstrate that it has procedures in place to satisfactorily deploy LaaR(s) providing Balancing Up Energy Service. All measurements shall confirm the additional delivery of energy due to the deployment of Balancing Up Energy Service in an amount equal to at least ninety-five percent (95%) and no more than one hundred and fifty percent (150%) of the amount requested by ERCOT. A deployment will be deemed acceptable when ERCOT confirms the interruption of the Load(s) within ten (10) minutes of issuance of the instruction by ERCOT.
 - (e) On successful demonstration of all test criteria, ERCOT shall qualify that the QSE is capable of providing Balancing Energy from LaaRs and shall provide a copy of the certificate to the QSE designating its qualification to provide Balancing Energy from LaaRs.

6.10.3.5 Reactive Supply from Generation Resources required to provide VSS

- (1) The Generation Entity must verify and maintain its stated Reactive Power capability for each of its Generation Resources required to provide VSS, as required by the Operating Guides. Generation Resources required to provide VSS reactive capability limits shall be specified considering nominal substation voltage.
- (2) The Generation Entity will conduct reactive capacity qualification tests to verify the maximum leading and lagging reactive capability of all Generation Resources required to provide VSS. Reactive capability tests will be performed on initial qualification and at a minimum of once every two years ERCOT may require additional testing if it has information indicating that current data is inaccurate. The Generation Entity is not obligated to place Generation Resources required to provide VSS On-line solely for testing. The reactive capability tests are run at a time agreed on in advance by the Generation Entity, its QSE, the applicable TDSP, and ERCOT.
- (3) Maximum lagging power factor reactive operating limit shall be demonstrated during peak Load Season, at or above ninety-five percent (95%) of the most currently tested net dependable megawatt capability, insofar as system voltage conditions and other factors will allow. The Generation Resource required to provide VSS should be required to maintain this level of Reactive Power for at least fifteen (15) minutes.
- (4) Maximum leading power factor reactive operating limit shall be demonstrated during light Load conditions, with the unit operating at a typical output for that condition, insofar as system voltage conditions and other factors will allow. The unit should be required to maintain this level of Reactive Power for at least fifteen (15) minutes.
- (5) The Generation Entity shall perform the unit Automatic Voltage Regulator (AVR) tests and shall supply AVR data as specified in the Operating Guides. The AVR tests will be performed on initial qualification and periodically at an ERCOT-set interval no more often than once every five (5) years. The AVR tests are run at a time agreed on in advance by the Generation Entity, its QSE, the applicable TDSP, and ERCOT.

6.10.3.6 System Black Start Capability

- (1) Qualification will be provided to any Black Start Resource that has met the following requirements:
 - (a) Verified control communication path performance;
 - (b) Verified primary and alternate voice circuits for receipt of instructions;
 - (c) Passed the basic starting test;
 - (d) Passed the line energizing test;
 - (e) Passed the Load carrying test;

generation schedule change for the measurement period (1 or 10 minute).
Generation schedule change per interval is defined as below:

$$\begin{aligned} & \{ \text{Absolute Value} \\ & [\quad (\text{ResourceSchedule} - \text{ResourceSchedulePreviousInterval}) \\ & \quad + (\text{BalancingDeployment} - \text{BalancingDeploymentPreviousInterval}) \quad] \\ & + \text{RegulationUpSchedule} \\ & + \text{RegulationDownSchedule} \} \end{aligned}$$

If this Participation Factor Calculation results in a value of less than 1%, then 1% will be used.

ϵ_i	is a constant derived from the targeted frequency bound. It is the targeted root-mean score of one (1) minute average frequency error from a schedule based on frequency performance over a given year as established according to NERC Performance Requirements by ERCOT and the appropriate ERCOT Subcommittee as assigned by TAC.
L_{10}	is a limit to recognize the desired performance of frequency for ERCOT as established according to NERC Performance Requirements by the appropriate ERCOT Subcommittee assigned by TAC. As of July 2003, L_{10} is defined as $(1.65 * E_{10} * 10 * Bias_{10})$ where E_{10} is 0.01315 Hz and $Bias_{10}$ is the ten (10) minute average of the ERCOT total bias used in the ACE calculation.
K	is a constant currently set to .81 which is established by the appropriate ERCOT Subcommittee as assigned by TAC. K should initially be set to .81 to provide an ERCOT wide L_{10} equivalent to the ERCOT wide L_{10} currently used by Control Areas in ERCOT. This constant can be adjusted to ensure correlation between passing the NERC CPS2 criteria and passing the SCE ten (10) minute control limit.

6.10.5.4 Responsive Reserve Services Deployment Performance Monitoring Criteria

QSEs providing Responsive Reserve Services must so indicate in the Scheduling Process. QSEs shall have Resources available to meet the schedule while adhering to the Responsive Reserve Service requirements detailed in the Operating Guides. On deployment of any Responsive Reserve Service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the instructed Responsive Reserve Service power requirement. ERCOT's calculation of SCE will determine the level of Responsive Reserve Service provided. Satisfactory control performance of the QSE providing Responsive Reserve Services shall be deemed satisfactory when two (2) out of the following three (3) conditions are met:

- (1) The QSE's SCE returns to the lesser of its pre-disturbance level or zero (0) within ten (10) minutes of the deployment of RRS.

- (2) The QSE's SCE must be above the minimum level at the ten (10) minute point after the deployment of RRS. The minimum level is defined as:

$$-1 * (\text{Min (20 MW, Max (.007 * actual generation, QSE_L10))})$$

The QSE_L10 value is defined as the actual value as indicated in the formula in Section 6.10.5.3 (2) ($L_{10} * K * \text{SQRT (Participation Factor)}$) at the ten (10) minute point after the deployment of RRS. The actual generation is the QSE's actual generation at the ten (10) minute point.

- (3) The QSE's average SCE for the ten (10) minute period following the RRS deployment must be above the minimum level. The minimum level is defined as:

$$-1 * \text{Max (QSE_L10, .45 * Max RRS Deployment in 10 minutes)}$$

If a QSE's SCE fails to meet two (2) out of the three (3) criteria stated above, the performance will be recalculated with the frequency bias term removed from the QSE's SCE equation. Based on the criteria above, ERCOT will assign a QSE a "PASS" or "FAIL" grade for that particular RRS deployment.

QSEs providing RRS for deployments lasting less than ten (10) minutes will be considered to have passed that particular deployment. The QSE must deliver the required RRS deployed at least ninety percent (90%) of the time during any single performance interval. A performance interval will be a minimum of two months and a maximum of four months. If a QSE has received twenty (20) deployments within two or three months, then that time period will count as the performance interval. Otherwise, the four month period will count as a performance interval regardless of how many deployments the QSE has received. QSEs must pass four (4) performance intervals out of the last six (6) performance intervals in order to be considered compliant. ERCOT will provide QSEs with monthly scores for informational purposes only.

LaaR deployments will be subject to a different set of compliance monitoring criteria. QSE's will be evaluated on their LaaR portfolio response to an ERCOT Operator's Verbal Deployment Instruction or based on their portfolio automated response to an under-frequency event. Criteria to be used for each event or instruction will be as follows:

- (1) A QSE's LaaR portfolio response is expected to be not less than ninety-five percent (95%), nor more than one hundred fifty percent (150%) of the RRS requested, subject to the declared capabilities of the QSE within ten (10) minutes of ERCOT's deployment Dispatch Instruction and maintained until recalled or the QSEs service Obligation expires; and
- (2) LaaRs providing a RRS response shall return to their committed operating level of RRS service as soon as practical considering process constraints and performance will be monitored against the requirements identified in Section 6.5.4 (13).

For all frequency deviations exceeding 0.175 Hz, ERCOT shall measure and record each two (2) second scan rate values of real power output for each QSE Resource providing Responsive Reserve Service. ERCOT shall measure and record the MW data beginning one (1) minute prior

to the start of the frequency excursion event or Manual / Dispatch Instruction until ten (10) minutes after the start of the frequency excursion event or Manual / Dispatch Instruction. Satisfactory performance is measured by comparing the actual response to the frequency response capability required in the Operating Guides.

Where multiple observations of operating response are available, the QSE must deliver the required frequency response capability seventy-five percent (75%) of the time during any single calendar quarter.

6.10.5.5 Non-Spinning Reserve Deployment Services Performance Monitoring Criteria

QSEs providing Non-Spinning Reserve Services must so indicate in the Scheduling Process. On deployment of any Non-Spinning Reserve Service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted to a base power function plus the instructed Non-Spinning Reserve power requirement. ERCOT's calculation of SCE will determine the level of Non-Spinning Reserve provided.

Control performance of the QSE providing Non-Spinning Reserve Services shall be deemed satisfactory when a QSE's average SCE must be greater than its average $-1 * QSE_L10$ for at least 75% of all 5-minute intervals for each hour of non-zero deployment of NSRS where the QSE_L10 value is defined as the actual value as indicated in the formula in Section 6.10.5.3 (2) ($L_{10} * K * SQRT(\text{Participation Factor})$).

[PRR436: Add the following paragraph to Section 6.10.5.5 upon system implementation:]

During periods when the Load level of a LaaR has been affected by a Dispatch Instruction from ERCOT, the performance of a LaaR in response to a Dispatch Instruction will be determined by subtracting the LaaR's actual Load response from its baseline. The actual Load response is the average of the real power consumption data being telemetered to ERCOT during the Settlement Interval indicated in the Dispatch Instruction.

The baseline capacity is calculated by measuring the average of the real power consumption for the four (4) Settlement Intervals prior to the Dispatch Instruction. During hours when the Load level of a LaaR has not been affected by a Dispatch Instruction from ERCOT, the Resource quantity provided by the LaaR scheduled or selected by ERCOT to provide Non-Spinning Reserve Service shall be measured as the LaaR's average Load level during the hour.

6.10.5.6 Combinations of Reliability Services Monitoring Criteria

QSEs providing any combination of services shall control their Resources to the additive result of any number of Dispatch Instructions deployed simultaneously. On deployment of any Balancing Energy, Regulation, Responsive Reserve, and Non-Spinning Reserve Service, the QSE shall control its Resources to operate to the final Resource bilateral schedules as converted

to a base power function plus the additive power requirement of each effective Dispatch Instruction. Satisfactory control performance of the QSE providing any combination of services will be determined by a combination of the following:

- (1) The criteria for SCE Monitoring at all times with exclusions as noted in Section 6.10.6; and
- (2) The criteria for Responsive Reserve if Responsive Reserve Service is one of the services deployed; and
- (3) The criteria for Non-Spinning Reserve Service if Non-Spinning is one of the services deployed.

6.10.6 *Ancillary Service Deployment Performance Conditions*

ERCOT shall determine the performance of providers of QSE SCE Performance under normal operating conditions. ERCOT shall remove from consideration of average performance of a QSE any period during which any of the following events has occurred and which does not have a passing score.

- (1) The two (2) hour period after the QSE has experienced a Forced Outage of generation and is under-generating or unexpected loss of private use network load and is over-generating;
- (2) The entire Settlement Intervals for all QSEs in which ERCOT has deployed or recalled Balancing Energy in response to an Unusual Event;
- (3) The entire Settlement Intervals in which ERCOT has issued a verbal Dispatch Instruction;
- (4) The period where ERCOT issues unit-specific instructions to any QSE outside of the unit's capabilities;
- (5) The period where ERCOT issues portfolio instructions to any QSE outside of the QSE's portfolio capabilities, including the QSE's bid ramp rate;
- (6) The entire Settlement Interval(s) in which a QSE is ramping into (from time of notification to time of deployment) or out of (from end of deployment to thirty (30) minutes later) a NSRS deployment;
- (7) If requested the day before the test by a QSE, the entire Settlement Interval(s) in which a QSE is performing tests required in Section 6.10, Ancillary Service Qualification, Testing and Performance Standards, and other regulatory agency-required tests;
- (8) The entire Settlement Interval(s) in which a QSE's Resource Plan shows only Uncontrollable Renewable Resources On-line; and

ISO TARIFF APPENDIX K
Ancillary Service Requirements Protocol

ISO TARIFF APPENDIX K
Ancillary Service Requirements Protocol

PART A
CERTIFICATION FOR REGULATION

- A 1** A Generator wishing to provide Regulation as an Ancillary Service from a Generating Unit whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following operating characteristics and technical requirements in order to be certified by the ISO to provide Regulation service unless granted a temporary exemption by the ISO in accordance with criteria which the ISO shall publish on the ISO's internet "Home Page;"
- A 1.1** **Operating Characteristics**
- A 1.1.1** the rated capacity of the Generating Unit must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;
- A 1.1.2** the maximum amount of Regulation to be offered must be reached within a period that may range from a minimum of 10 minutes to a maximum of 30 minutes, as such period may be specified by the ISO and published on the ISO's internet "Home Page;"
- A 1.2** **Technical Requirements**
- A 1.2.1** **Control**
- A 1.2.1.1** a direct, digital, unfiltered control signal generated from the ISO EMS through a standard ISO direct communication and direct control system, must meet the minimum performance standards for communications and control which will be developed and posted by the ISO on its internet "Home Page;"
- A 1.2.1.2** the Generating Unit power output response (in MW) to a control signal must meet the minimum performance standards for control and unit response which will be developed and posted by the ISO on its internet "Home Page." As indicated by the Generating Unit power output (in MW), the Generating Unit must respond immediately, without manual Generating Unit operator intervention, to control signals and must sustain its specified ramp rate, within specified Regulation limits, for each minute of control response (MW/minute);
- A 1.2.2** **Monitoring:**
- the Generating Unit must have a standard ISO direct communication and direct control system to send signals to the ISO EMS to dynamically monitor, at a minimum the following:

- A 1.2.2.1** actual power output (MW);
- A 1.2.2.2** high limit, low limit and rate limit values as selected by the Generating Unit operator; and
- A 1.2.2.3** in-service status indication confirming availability of Regulation service.
- A 1.2.3 Voice Communications:**
- ISO approved primary and back-up voice communication must be in place between the ISO Control Center and the operator controlling the Generating Unit at the generating site and between the Scheduling Coordinator and the operator. The primary dedicated voice communication between the ISO Control Center and the operator controlling the Generating Unit at the generating site must be digital voice communication, as provided by a standard ISO direct communication and direct control system; and
- A 1.3** the communication and control system and the Generating Unit must pass a qualification test to demonstrate the overall ability to provide Regulation meeting the performance requirements of the ASRP for Regulation.
- A 2** A Generator wishing to be considered for certification for Regulation service by the ISO must make a written request to the ISO, giving details of the technical capability of the Generating Units concerned and identifying the Scheduling Coordinator through whom the Generator intends to offer Regulation service. The Generator shall at the same time send a copy of its request to that Scheduling Coordinator. Technical review request forms will be available from the ISO.
- A 3** No later than one week after receipt of the Generator's request, the ISO shall provide the Generator with a listing of required interface equipment for Regulation, including a standard ISO direct communication and direct control system. The ISO shall send a copy of the listing to the Generator's Scheduling Coordinator.
- A 4** The Generator may propose alternatives that the Generator believes may provide an equivalent level of communication and control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- A 5** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Generator and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- A 6** Upon agreement as to any alternative method of communication and control to be used by the Generator, the ISO shall provisionally approve the proposal in writing providing a copy to the Generator's Scheduling Coordinator at the same time. If agreed by the ISO, the Generator may then proceed to procure and install the equipment and make arrangements for the required communication and control.

- A 7** Design, acquisition, and installation of the ISO-approved communication and control equipment shall be under the control of the ISO. The ISO shall bear no cost responsibility or functional responsibility for such equipment, except that the ISO shall arrange for and monitor the maintenance of the communication and control system at the Generator's expense, unless otherwise agreed by the ISO and the Generator. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO EMS at its own cost.
- A 8** The ISO, in cooperation with the Generator shall perform testing of the communication and control equipment to ensure that the communication and control system performs to meet the ISO requirements.
- A 9** When the ISO is satisfied that the communication and control systems meet the ISO's requirements, the Generator shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Generator's request, accept a proposed time if possible or suggest at least three alternatives to the Generator. If the ISO responds by suggesting alternatives, the Generator shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator shall inform its Scheduling Coordinator of the agreed date and time of the test.
- A 10** Testing shall be performed by the ISO, with the cooperation of the Generator. Such tests shall include, but not be limited to, the following:
- A 10.1** confirmation of control communication path performance;
- A 10.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- A 10.3** confirmation of the Generating Unit control performance; and
- A 10.4** confirmation of the ISO EMS control to include changing the Generating Unit output over the range of Regulation proposed at different Set Points, from minimum to maximum output, and at different rates of change from the minimum to the maximum permitted by the design of the Generating Unit.
- A 11** Upon successful completion of the test, the ISO shall certify the Generating Unit as being permitted to provide Regulation as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its Generating Unit data base to reflect the permission for the Generating Unit to provide Regulation service.
- A 12** The Scheduling Coordinator may bid Regulation service from the certified Generating Unit into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.

A 13 The certification to provide Regulation shall remain in force until:

- (a) withdrawn by the Scheduling Coordinator or the Generator by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day; or
- (b) if the Generating Unit obtained ISO certification on the basis of a prior communication and control technology, until revoked by the ISO for failure to comply with the requirement set forth in A 13.1 that the Generating Unit install an ISO-specified standard ISO direct communication and direct control system (unless exempted by the ISO).

A 13.1 Unless exempted by the ISO, if the Generating Unit obtained ISO certification on the basis of a prior communication and control technology, the ISO shall provide written notice to the Generator of the Generator's obligation to install an ISO-specified standard direct communication and direct control system along with a required date for said work to be completed as mutually agreed upon by the ISO and the Generator. Failure to meet the completion date shall be grounds for the revocation of certification, provided that the ISO must provide the Generator with at least ninety (90) days advance notice of the proposed revocation.

A 14 THE CERTIFICATION MAY BE REVOKED BY THE ISO ONLY UNDER PROVISIONS
OF THE ASRP OR THE ISO TARIFF.

PART B

CERTIFICATION FOR SPINNING RESERVE

- B 1** A Generator wishing to provide Spinning Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Spinning Reserve service:
- B 1.1** the rated capacity of the Generating Unit must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;
- B 1.2** the minimum governor performance of the Generating Unit or System Resource shall be as follows:
- B 1.2.1** 5% drop;
- B 1.2.2** governor deadband must be plus or minus 0.036Hz; and
- B 1.2.3** the power output must change within one second for any frequency deviation outside the governor deadband.
- B 1.3** the operator of the Generating Unit or System Resource must have a means of receiving Dispatch instructions to initiate an increase in real power output (MW) within one minute of the ISO Control Center determination that Energy from Spinning Reserve capacity must be Dispatched;
- B 1.4** the Generating Unit or System Resource must be able to increase its real power output (MW) by the maximum amount of Spinning Reserve to be offered within ten minutes;
- B 1.5** ISO approved voice communications services must be in place to provide both primary and alternate voice communication between the ISO Control Center and the operator controlling the Generating Unit or System Resource; and
- B 1.6** The communication system and the Generating Unit or System Resource must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Spinning Reserve.
- B 2** A Generator or System Unit wishing to be considered for certification for Spinning Reserve service by the ISO must make a written request to the ISO, giving details of the technical capability of the Generating Units or System Resources concerned and identifying the Scheduling Coordinator through whom the Generator or System Unit intends to offer Spinning Reserve service. The Generator or System Unit shall at the same time send a copy of its request to that Scheduling Coordinator. Technical review request forms will be available from the ISO.

- B 3** No later than one week after receipt of the request, the ISO shall provide the Generator or System Unit with a listing of acceptable communication options and interface equipment options for Spinning Reserve. The ISO shall send a copy of the listing to the Generator's or System Unit's Scheduling Coordinator.
- B 4** The Generator or System Unit may elect to implement any of the approved options defined by the ISO, and, if it wishes to proceed with its request for certification, shall give written notice to the ISO of its selected communication option, with a copy to its Scheduling Coordinator.
- B 5** When it receives the Generator's or System Unit's notice, the ISO shall notify the Generator or System Unit and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment, the Generator or System Unit may proceed as indicated below to secure the necessary facilities and capabilities required.
- B 6** The Generator or System Unit may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- B 7** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Generator or the System Unit and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- B 8** Upon agreement as to the method of communication and control to be used by the Generator or System Resource, the ISO shall provisionally approve the Generator's proposal or the System Resource's proposal in writing providing a copy to the Generator's or System Resource's Scheduling Coordinator at the same time. The Generator or System Resource may then proceed to procure and install the equipment and make arrangements for the required communication.
- B 9** Design, acquisition, and installation of the Generator's equipment or the System Resource's equipment shall be under the control of the respective Generator or System Resource. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to its own equipment at its own cost.
- B 10** The Generator or System Resource shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.

- B 11** When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Generator or System Resource shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the request, accept a proposed time if possible or suggest at least three alternatives to the Generator or System Resource. If the ISO responds by suggesting alternatives, the Generator or System Resource shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator or System Resource shall inform its Scheduling Coordinator of the agreed date and time of the test.
- B 12** Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:
- B 12.1** confirmation of control communication path performance for Dispatch instruction;
- B 12.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- B 12.3** confirmation of the Generating Unit or System Resource performance to include changing the Generating Unit or System Resource output over the range of Spinning Reserve proposed from minimum to maximum output, and at different rates of change from the minimum to the maximum permitted by the design of the Generating Unit or System Resource; and
- B 12.4** testing the drop characteristic of the Generating Unit or System Resource by simulating frequency excursions outside the allowed deadband and measuring the response of the Generating Unit or System Resource.
- B 13** Upon successful completion of the test the ISO shall certify the Generating Unit or System Resource as being permitted to provide Spinning Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change the Generating Unit or System Resource data base to reflect the ability of the Generating Unit to provide Spinning Reserve.
- B 14** The Scheduling Coordinator may bid Spinning Reserve from the certified Generating Unit or System Resource into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the Second Trading Day after the ISO issues the certificate.
- B 15** The certification to provide Spinning Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Generator or System Resource by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.
- B 16** The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

PART C

CERTIFICATION FOR NON-SPINNING RESERVE

- C 1** An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:
- C 1.1** the rated capacity of the Generating Unit or System Resource must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;
- C 1.2** the Generating Unit must be able to increase output as soon as possible to the value indicated in a Dispatch instruction, reaching the indicated value within ten minutes after issue of the instruction and be capable of maintaining output for 2 hours.
- C 2** An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service from Curtailable Demand whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:
- C 2.1** the operator must be able to completely disconnect the required Load pursuant to a Dispatch instruction within ten minutes after issue of the instruction;
- C 2.2** the minimum change in the electrical consumption of the Load must be at least 1 MW; and
- C 2.3** the Load must be capable of being interrupted for at least two hours.
- C 3** An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service, whether pursuant to the ISO's auction or as part of a self-provision arrangement, must also meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:
- C 3.1** the operator of the Generating Unit, System Resource or the Curtailable Demand must have a means of receiving a Dispatch instruction to initiate an increase in real power output or a reduction in Demand (MW) within one minute of the ISO Control Center's determination that Non-Spinning Reserve capacity must be Dispatched; and
- C 3.2** the communication system and the Generating Unit, System Resource or Load must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Non-Spinning Reserve.
- C 4** An Ancillary Service Provider wishing to be considered for certification for Non-Spinning Reserve service must make a written request to the ISO, giving details of the technical capability of the Generating Unit, System Resource or Load concerned and identifying the Scheduling Coordinator through whom the Ancillary Service Provider intends to offer Non-Spinning Reserve. The Ancillary Service Provider shall at the same time send a

copy of the request to that Scheduling Coordinator. Technical Review request forms will be available from the ISO.

- C 5** No later than one week after receipt of the Ancillary Service Provider's request, the ISO shall provide the Ancillary Service Provider with a listing of acceptable communication options and interface equipment options for Non-Spinning Reserve. The ISO shall send a copy of the listing to the Ancillary Service Provider's Scheduling Coordinator.
- C 6** The Ancillary Service Provider may elect to implement any of the certification, the Ancillary Service Provider shall give written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.
- C 7** When it receives the Ancillary Service Provider's notice, the ISO shall notify the Ancillary Service Provider and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Ancillary Service Provider may proceed as indicated below to secure the necessary facilities and capabilities required.
- C 8** The Ancillary Service Provider may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- C 9** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Ancillary Service Provider and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- C 10** Upon agreement as to the method of communication and control to be used by the Ancillary Service Provider, the ISO shall provisionally approve the proposal in writing providing a copy to the Ancillary Service Provider's Scheduling Coordinator at the same time. The Ancillary Service Provider may then proceed to procure and install the equipment and make arrangements for the required communication.
- C 11** Design, acquisition, and installation of the Ancillary Service Provider's equipment shall be under the control of the Ancillary Service Provider. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be

responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.

- C 12** The Ancillary Service Provider shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.
- C 13** When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Ancillary Service Provider shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Ancillary Service Provider's request, accept a proposed time if possible or suggest at least three alternatives. If the ISO responds by suggesting alternatives, the Ancillary Service Provider shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Ancillary Service Provider shall inform its Scheduling Coordinator of the agreed date and time of the test.
- C 14** Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:
- C 14.1** confirmation of control communication path performance;
- C 14.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- C 14.3** confirmation of the Generating Unit, System Resource or Load control performance; and
- C 14.4** confirmation of the range of Generating Unit or System Resource control to include changing the output over the range of Non-Spinning Reserve proposed.
- C 15** Upon successful completion of the test, the ISO shall certify the Generating Unit, System Resource or Load as being permitted to provide Non-Spinning Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its data base to reflect the permission for the Generating Unit or Load to provide Non-Spinning Reserve service.
- C 16** The Scheduling Coordinator may bid Non-Spinning Reserve service from the certified Generating Unit or Load into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.
- C 17** The certification to provide Non-Spinning Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Ancillary Service Provider by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.

- C 18** The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

PART D

CERTIFICATION FOR REPLACEMENT RESERVE

- D 1** An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:
- D 1.1** the rated capacity of the Generating Unit or System Resource must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;
- D 1.2** the operator of the Generating Unit must be able to increase output as quickly as possible to a value indicated in a Dispatch instruction, reaching the indicated value in sixty minutes or less after issue of the instruction.
- D 2** An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service from Curtailable Demand whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:
- D 2.1** the operator must be able to completely disconnect the required Load pursuant to a Dispatch instruction within sixty minutes after issue of the instruction;
- D 2.2** the minimum change in the electrical consumption of the Load must be at least 1 MW; and
- D 2.3** the Load must be capable of being interrupted for at least two hours.
- D 3** An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service, whether pursuant to the ISO's auction or as part of a self-provision arrangement, must also meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:
- D 3.1** the operator of the Generating Unit, System Resource or the Curtailable Demand must have a means of receiving a Dispatch instruction to initiate an increase in real power output or a reduction in Demand (MW) within one minute of the ISO Control Center's determination that Replacement Reserve capacity must be Dispatched; and
- D 3.2** the communication system and the Generating Unit or Load must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Replacement Reserve.
- D 4** An Ancillary Service Provider wishing to be considered for certification for Replacement Reserve service must make a written request to the ISO, giving details of the technical capability of the Generating Unit, System Resource or the Load concerned and identifying the Scheduling Coordinator through whom the Ancillary Service Provider intends to offer Replacement Reserve. The Ancillary Service Provider shall at the same time send a copy of its request to that Scheduling Coordinator. Technical Review request forms will be available from the ISO.
- D 5** No later than one week after receipt of the Ancillary Service Provider's request, the ISO shall provide the Ancillary Service Provider with a listing of acceptable communication options and interface equipment options for Replacement Reserve. The ISO shall send a copy of the listing to the Ancillary Service Provider's Scheduling Coordinator.
- D 6** The Ancillary Service Provider may elect to implement any of the options defined by the ISO, and, if it wishes to proceed with its request for certification, the Ancillary Service Provider shall give

written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.

- D 7** When it receives the Ancillary Service Provider's notice, the ISO shall notify the Ancillary Service Provider and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Ancillary Service Provider may proceed as indicated below to secure the necessary facilities and capabilities required.
- D 8** The Ancillary Service Provider may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- D 9** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision shall be provided not later than six weeks after the proposal is received by the ISO. The Ancillary Service Provider and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- D 10** Upon agreement as to the method of communication and control to be used by the Ancillary Service Provider, the ISO shall provisionally approve the proposal in writing providing a copy to the Ancillary Service Provider's Scheduling Coordinator at the same time. The Ancillary Service Provider may then proceed to procure and install the equipment and make arrangements for the required communication.
- D 11** Design, acquisition, and installation of the Ancillary Service Provider's equipment shall be under the control of the Ancillary Service Provider. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.
- D 12** The Ancillary Service Provider shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.
- D 13** When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Ancillary Service Provider shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Ancillary Service Provider's request, accept a proposed time if possible or suggest at least three alternatives. If the ISO responds by suggesting alternatives, the Ancillary Service Provider shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Ancillary Service Provider shall inform its Scheduling Coordinator of the agreed date and time of the test.
- D 14** Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:
- D 14.1** confirmation of control communication path performance;
- D 14.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- D 14.3** confirmation of the Generating Unit, System Resource or Load control performance; and

- D 14.4** confirmation of the range of Generating Unit or System Resource control to include changing the Generating Unit output over the range of Replacement Reserve proposed.
- D 15** Upon successful completion of the test the ISO shall certify the Generating Unit, System Resource or Load as being permitted to provide Replacement Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its data base to reflect the permission for the Generating Unit or Load to provide Replacement Reserve service.
- D 16** The Scheduling Coordinator may bid Replacement Reserve service from the certified Generating Unit or Load into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.
- D 17** The certification to provide Replacement Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Ancillary Service Provider by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.
- D 18** **THE CERTIFICATION MAY BE REVOKED BY THE ISO ONLY UNDER PROVISIONS OF THE ASRP OR THE ISO TARIFF.**



California ISO
Your Link to Power

Draft

Business Practice Manual for Market Operations

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Disclaimer

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TABLE OF CONTENTS

1. Introduction	1
1.1 Purpose of CAISO Business Practice Manuals	1
1.2 Purpose of this Business Practice Manual	2
1.3 References	3
2. Market Operations Overview	4
2.1 Market Entities	4
2.1.1 CAISO	4
2.1.2 Scheduling Coordinators	5
2.1.3 Participating Generators	5
2.1.4 Participating Loads	5
2.1.5 Non-Participating Loads	12
2.1.6 Utility Distribution Companies	12
2.1.7 Metered Subsystems	13
2.1.8 Control Areas	13
2.1.9 Participating Transmission Owners	14
2.2 Products & Services	15
2.2.1 Energy	15
2.2.2 Ancillary Services	15
2.2.3 Residual Unit Commitment Capacity	16
2.2.4 Congestion Revenue Rights	16
2.3 CAISO Markets	16
2.3.1 Day-Ahead Market Processes	18
2.3.2 Real-Time Market Processes	19
2.4 Roles & Responsibilities	21
2.4.1 Utility Distribution Companies	22
2.4.2 Metered Subsystems	22
2.4.3 Participating Transmission Owners Information	23
2.4.4 Participating Generators & Participating Loads	24
2.4.5 Scheduling Coordinator Responsibilities	25
2.5 Market Information	26
2.5.1 Resource Static Data	27
2.5.2 Bids	31

2.5.3	Inter-SC Trades	35
2.5.4	Existing Transmission Contracts, Transmission Owner Rights, & Converted Rights.....	35
3.	Full Network Model.....	36
3.1	Model Description.....	36
3.1.1	Real-Time Data.....	37
3.1.2	Generation Distribution Factors	38
3.1.3	Modeling Points	39
3.1.4	Load Distribution Factors.....	40
3.1.5	Aggregated Pricing Nodes.....	41
3.1.6	Losses	42
3.1.7	Nomograms	47
3.1.8	Transmission Element & Transmission Interfaces.....	49
3.1.9	Scheduling Points	50
3.2	Locational Marginal Prices	51
3.2.1	LMP Disaggregation	51
3.2.2	System Marginal Energy Cost	58
3.2.3	Marginal Cost of Losses	58
3.2.4	Marginal Cost of Congestion	58
3.3	Market Interfaces.....	59
4.	Ancillary Services	60
4.1	Ancillary Services Regions	60
4.1.1	Ancillary Services Region Definition	60
4.1.2	Ancillary Services Region Change Process	63
4.2	Ancillary Services Requirements.....	64
4.2.1	Self-Provided Ancillary Services.....	66
4.2.2	Conversion of Conditionally Qualified SPAS to Energy.....	69
4.2.3	Conversion of Conditionally Unqualified SPAS to Qualified SPAS.....	70
4.2.4	Other Details of SPAS	70
4.2.5	Ancillary Service Award Allocation of Energy Bids	71
4.2.6	Regulation Up & Down Requirements	73
4.2.7	Operating Reserve Requirements	74
4.2.8	Maximum Upward Capacity Constraint	76

4.3	Ancillary Services Procurement.....	76
4.3.1	Ancillary Services Procurement in Day-Ahead Market	76
4.3.2	Ancillary Services Procurement in Real-Time Market	77
4.4	Ancillary Services Marginal Prices	78
4.5	Ancillary Services Considerations	79
4.6	Ancillary Services Certification & Testing Requirements.....	80
4.6.1	Regulation Certification & Testing Requirements	81
4.6.2	Spinning Reserve Certification & Testing Requirements	81
4.6.3	Non-Spinning Reserve Certification & Testing Requirements	82
5.	Existing Transmission Contracts, Converted Rights & Transmission Ownership Rights.....	84
5.1	Continuation of Rights & Obligations.....	84
5.1.1	Existing Transmission Contracts	84
5.1.2	Converted Rights	85
5.1.3	Non-Participating Transmission Owners	86
5.1.4	Transmission Ownership Rights	86
5.1.5	Transmission Rights & Curtailment Instructions	87
5.1.6	ETC and CVR Scheduling Time Requirement.....	89
5.1.7	TOR Scheduling Time Requirements	90
5.1.8	Scheduling Priority for Transmission Rights	92
5.1.9	ETC, CVR & TOR Settlement.....	92
5.1.10	ETC and CVR Scheduling Requirements.....	93
5.1.11	ETCs, CVRs and TORs Treatment in the Release of CRRs	94
5.1.12	TOR Scheduling Requirements	95
5.2	Available Transfer Capability Calculation	96
5.2.1	ATC Calculation before DAM Closes.....	96
5.2.2	ATC Calculation After DAM Completes & Before RTM Closes	97
5.2.3	ATC Calculation After RTM Completes	98
6.	Day-Ahead Market Processes.....	99
6.1	Pre-Market Activities.....	99
6.1.1	Congestion Revenue Rights	99
6.1.2	Full Network Model Build	99
6.1.3	Bid Information.....	99

6.1.4	Outage Information	100
6.1.5	CAISO Demand Forecast Information	100
6.1.6	Determine Operating Transfer Capability	101
6.1.7	Before Day-Ahead Market is Closed	101
6.1.8	Overgeneration Condition	102
6.2	Day-Ahead Market Timeline	102
6.3	Scheduling Coordinator Activities	103
6.3.1	Submit Bids	103
6.3.2	Interchange Transactions & e-Tagging	104
6.3.3	Respond to Day-Ahead Market Published Schedules & Awards	104
6.4	CAISO Activities	105
6.4.1	Accept Day-Ahead Market Inputs	105
6.4.2	Disseminate Pre-Market Communications	105
6.4.3	Disseminate Post Market Close Information	106
6.4.4	Close Day-Ahead Market	106
6.4.5	Execute Day-Ahead Market Applications	107
6.4.6	Publish Reports to Scheduling Coordinators	107
6.4.7	Resource Commitment	109
6.5	Market Power Mitigation & Reliability Requirement Determination	110
6.5.1	Reliability Requirement Determination & Local Market Power Mitigation	111
6.5.2	Day-Ahead & HASP RMR	112
6.5.3	Competitive Path Criteria	113
6.5.4	Default Energy Bids	114
6.5.5	Bid Adder for Frequently Mitigated Units	115
6.6	Integrated Forward Market	115
6.6.1	IFM Inputs	116
6.6.2	IFM Constraints & Objectives	119
6.6.3	Co-optimization of Energy & Ancillary Services	120
6.6.4	Uneconomic Adjustments in IFM	121
6.6.5	Pricing Run for IFM	123
6.6.6	IFM Outputs	123
6.6.7	Energy Settlement	124
6.7	Residual Unit Commitment	125

6.7.1	RUC Objective	126
6.7.2	RUC Inputs	127
6.7.3	RUC Execution	139
6.7.4	RUC Outputs	140
6.8	Extremely Long-Start Commitment	142
6.8.1	ELC Process	143
6.8.2	Energy Bids & Ancillary Services Bids for the Trading Day for ELC Units ...	145
6.8.3	Energy Bids & Ancillary Services Bids for the Day after the Trading Day	146
6.8.4	Energy Balance Equation and AS Requirements	146
6.8.5	Outage Considerations	147
6.8.6	Initial & Boundary Conditions	147
6.8.7	Constraints	147
6.8.8	Usage of ELC Output in MPM & IFM Applications	148
7.	Real-Time Processes	149
7.1	Differences from IFM	149
7.1.1	Real-Time Market Timelines	151
7.1.2	Real-Time Dispatch Principles	152
7.2	Scheduling Coordinator Activities	152
7.2.1	Submit Bids	152
7.2.2	Interchange Transactions & e-Tagging	153
7.2.3	Respond to Commitment & Dispatch Instructions	153
7.3	CAISO Activities	156
7.3.1	Accept Hourly HASP & Real-Time Market Inputs	156
7.3.2	Close Real-Time Market	160
7.3.3	Execute Real-Time Applications	160
7.3.4	Publish Real-Time Processes Reports to Scheduling Coordinators	162
7.4	MPM-RRD for Real-Time	162
7.5	Hour-Ahead Scheduling Process	162
7.5.1	Hourly Schedule Changes & Dispatch Priorities	163
7.5.2	HASP Inputs	165
7.5.3	HASP Constraints & Objectives	168
7.5.4	HASP Outputs	170
7.6	Real-Time Unit Commitment	172

7.6.1	Real-Time Unit Commitment Inputs.....	172
7.6.2	Real-Time Unit Commitment Constraints & Objectives	174
7.6.3	Real-Time Unit Commitment Outputs.....	176
7.6.4	Real-Time Unit Commitment Pricing	176
7.7	Short-Term Unit Commitment.....	176
7.7.1	Short-Term Unit Commitment Inputs	177
7.7.2	Short-Term Unit Commitment Constraints & Objectives	177
7.7.3	Short-Term Unit Commitment Outputs	178
7.8	Real-Time Economic Dispatch	178
7.8.1	Real-Time Economic Dispatch Inputs.....	180
7.8.2	Real-Time Economic Dispatch Constraints & Objectives	181
7.8.3	Real-Time Economic Dispatch Outputs.....	185
7.9	Real-Time Contingency Dispatch	185
7.9.1	Real-Time Contingency Dispatch Inputs	187
7.9.2	Real-Time Contingency Dispatch Constraints & Objectives.....	187
7.9.3	Real-Time Contingency Dispatch Locational Marginal Prices	187
7.9.4	Real-Time Contingency Dispatch Outputs.....	188
7.10	Real-Time Manual Dispatch	188
7.10.1	Real-Time Manual Dispatch Inputs.....	190
7.10.2	Real-Time Manual Dispatch Constraints & Objectives	190
7.10.3	Real-Time Manual Dispatch Outputs.....	190
7.11	Exceptional Dispatch.....	190
7.11.1	System Reliability Exceptional Dispatches.....	191
7.11.2	Other Exceptional Dispatch	191
8.	Post Market Activities.....	193
8.1	Price Validation.....	193
8.1.1	Market Validation	194
8.1.2	General Scope of Price Corrections	194
8.1.3	Scope of Price Corrections for DAM.....	195
8.1.4	Scope of Price Corrections for RTM	196
8.1.5	Price Correction Process	197
8.1.6	Procedures	199

Attachments:

- Attachment A: Market Optimization
- Attachment B: Market Interfaces
- Attachment C: Competitive Path Assessment
- Attachment D: Expected Energy Calculation

List of Exhibits:

Exhibit 1-1: CAISO BPMs	1
Exhibit 2-1: CAISO Markets – Overview Timeline	17
Exhibit 2-2: Master File Data.....	27
Exhibit 3-1: Generator Telemetry Data from EMS to RTM	37
Exhibit 3-2: Load Telemetry Data from EMS to RTM.....	38
Exhibit 3-3: Connectivity Node Data from SE to RTM	38
Exhibit 3-4: Load Aggregation Point	41
Exhibit 3-5: Modeling Point	41
Exhibit 3-6: CAISO Power Balance Relationship.....	44
Exhibit 3-7: Marginal Losses - Conceptual Model.....	46
Exhibit 3-8: Nomogram	48
Exhibit 3-9: Market Interfaces	59
Exhibit 4-1: Summary of Initial AS Regions	62
Exhibit 4-2: Qualification Process of Submissions to Self-Provide an AS	69
Exhibit 6-1: Day-Ahead Market Timeline	103
Exhibit 6-2: Generating Unit Commitment Selection by Application	109
Exhibit 6-3: Day-Ahead Market Clearing Price for Energy – Ignoring Marginal Losses & Congestion.....	121
Exhibit 6-4: Capacity Available for RUC	136
Exhibit 6-5: RUC Start Up, Minimum Load, & Availability Bid Eligibility.....	136
Exhibit 6-6: Overview of ELC Process	144
Exhibit 7-1: HASP/STUC/RTUC Timelines	151
Exhibit 7-2: Real-Time Applications	161
Exhibit 7-3: Real-Time Market Clearing Price for Energy (Ignoring Marginal Losses & Congestion)	170
Exhibit 7-4: Advisory Schedule from HASP	171

4. Ancillary Services

Welcome to the *Ancillary Services* (AS) section of the CAISO *BPM for Market Operations*. In this section, you will find the following information:

- A description of each of the AS Regions
- How CAISO determines AS requirements
- How CAISO procures AS
- How CAISO calculates AS Marginal Prices
- Other AS considerations
- Certification and testing requirements

4.1 Ancillary Services Regions

AS Regions are network partitions that are used to implicitly impose regional constraints in the procurement of AS, where the AS Region is defined as a set of PNodes and regional AS procurement is exclusively from resources associated with the PNodes defining the region.

AS regional constraints reflect transmission limitations between AS Regions that restrict the use of AS procured in one AS Region to cover for Outages in another AS Region and constraints between the regions. AS regional constraints secure a minimum AS procurement (to ensure reliability) and/or a maximum AS procurement target (that increases the probability of deliverability of AS to each Region), such that the total AS procurement among Regulation Up, Spinning Reserve, and Non-Spinning Reserve reflects the current system topology and deliverability needs. Ancillary Service Regions and Subregions are defined in the CAISO Tariff in Section 8.3.3. New Ancillary Service Regions and Subregions may only be established after a stakeholder process and through the filing with FERC of a tariff amendment.

4.1.1 Ancillary Services Region Definition

There are always at least two AS Regions with non-zero minimum procurement limits applied:

- **Expanded System Region** – The Expanded System Region is defined as the entire CAISO Control Area plus all System Resources at Scheduling Points at an outside boundary of the CAISO Control Area. Total CAISO AS procurement requirements for each of the four AS that are further described in the *BPM for Market Instruments* are procured from certified Generating Units and Participating Loads and System Resources within the Expanded System Region.
- **System Region** – The System Region is defined as the sub-set of certified resources defined in the Expanded System Region that are located internal to the CAISO Control

Area. The minimum AS regional constraints for the AS System Region are only a percentage of the AS requirements for the Expanded System Region, currently at 50%, to limit the AS procurement from System Resources for reliability purposes. The purpose of this limitation is to guard against the consequences of losing interconnection tie facilities, which would limit the AS procurement, i.e., AS delivered over a tie cannot protect the tie itself.

Besides the Expanded System Region and the System Region, eight other AS Regions are defined to ensure appropriate distribution of the AS procured for the CAISO Control Area. These sub-AS Regions are defined to account for expected Congestion on the Transmission Interfaces (internal to the CAISO Control Area), as well as other system conditions, that may impact the ability of the CAISO to convert AS reserves to Energy without exacerbating Congestion on the paths that are internal to the CAISO Control Area.

The eight sub-AS Regions account for expected Congestion on Path 15 and Path 26. For a given hour of AS procurement, one of the following conditions is assumed:

- 1) No congestion forecasted on either of these two Transmission Interfaces.
- 2) Forecasted congestion on Path 26 in the north to south direction, which requires a minimum procurement limit on the set of resources that are south of Path 26.
- 3) Forecasted congestion on Path 15 in the north to south direction, which requires a minimum procurement limit on the set of resources that are south of Path 15.
- 4) Forecasted congestion on Path 15 in the south to north direction, which requires a minimum procurement limit on the set of resources that are north of Path 15.
- 5) Forecasted congestion on Path 26 in the south to north direction, which requires a minimum procurement limit on the set of resources that are north of Path 26.
- 6) Forecasted congestion on Path 15 in the north to south direction simultaneous with south to north Congestion on Path 26. While this scenario is expected to be rare, it can be addressed by setting maximum procurement limits on each of the south of Path 26 AS sub-Region and the north of Path 15 AS sub-Region.
- 7) Forecasted congestion on Path 15 in the south to north direction simultaneous with north to south Congestion on Path 26. While this scenario is expected to be rare, it can be addressed by setting minimum procurement limits on each of the south of Path 26 AS sub-Region and the north of Path 15 AS sub-Region.

For each of these conditions (Items 2 through 7 above), the AS sub-Region may include the System Resources that are interconnected to that portion of the CAISO Controlled Grid. The determination of whether or not to include the System Resources in the sub-AS Region depends on the nature of the system conditions, including the expected loading on the Transmission Interfaces that interconnect System Resources to the CAISO Controlled Grid

Based on these criteria, there are eight AS Sub-Regions in addition to the Expanded System Region and the System Region, as follows:

Exhibit 4-1: Summary of Initial AS Regions

	AS Region Name	Description of AS Region (set of resources included in AS Region)		AS Region Status
		Internal CAISO Control Area	Intertie Resources (current Scheduling Points)	
1	<i>Expanded System</i>	All internal Generators	All	Active
2	<i>System</i>	All internal Generators	None	Active
3	<i>South of Path 15</i>	All Generators residing South of Path 15	None	Active
4	<i>Expanded South of Path 15</i>	All Generators residing South of Path 15	NW3, SR3, NV3, NV4, AZ2, AZ3, AZ5, LC1, LC2, LC3, MX, LA1, LA2, LA3, LA4, LA7	Active
5	<i>South of Path 26</i>	All Generators residing South of Path 26	None	Active
6	<i>Expanded South of Path 26</i>	All Generators residing South of Path 26	NW3, SR3, NV3, NV4, AZ2, AZ3, AZ5, LC1, LC2, LC3, MX, LA1, LA2, LA3, LA4, LA7	Active
7	<i>North of Path 15</i>	All Generators residing North of Path 15	None	Active
8	<i>Expanded North of Path 15</i>	All Generators residing North of Path 15	NW1, NW2, SR5, SR2, SMUD, TID, Sutter	Active
9	<i>North of Path 26</i>	All Generators residing North of Path 26	None	Active
10	<i>Expanded North of Path 26</i>	All Generators residing North of Path 26	NW1, NW2, SR5, SR2, SMUD, TID, Sutter	Active

All AS Regions shown in Exhibit 4-1 are “active”. However, this does not necessarily mean that a minimum (or maximum) procurement limit is enforced for each of these AS Sub-Regions for a

given hour. The term “active” here indicates that the AS Sub-Region is defined in the CAISO Tariff, and is included in the daily determination of applicable Regional AS limits. However, an AS Sub-Region may be “active” but also have a zero MW minimum procurement limit and a 9,999 MW maximum procurement limit, which effectively renders the AS Sub-Region as unconstrained.

AS requirements, procurement, and pricing are expressed by AS Region. The minimum and/or maximum procurement constraints are each determined individually and serve as separate constraints on the procurement of resources. A purchase of AS capacity in a specific Location on the grid may contribute to meet the requirements of several AS Regions simultaneously.

As conditions evolve, additional AS Regions may be needed to manage AS procurement limits for sub-AS Regions. These conditions may include:

- A pocket of Generation or Load for which more localized limits are needed to ensure sufficient capacity procurement under certain system conditions
- A System Resource at a Scheduling Point from which CAISO foresees a need to limit the AS procurement, under certain system conditions

CAISO follows the AS Region change process described in the next section, as power system conditions warrant.

4.1.2 Ancillary Services Region Change Process

The CAISO will look at a number of factors in determining whether to consider adjusting the boundaries of the existing Ancillary Service Regions or creating a new Ancillary Service Region. The conditions include, but are not limited to, operational reliability needs, the pattern of Load growth in the CAISO Control Area, the addition of new generating resources, the retirement of existing generating resources, the addition of new transmission facilities, changes in regional transmission limitations, changes in Available Transfer Capacity, and extended transmission or generating resource outages.

Finally, if the CAISO considers adjusting the boundaries of the existing Ancillary Service Regions or creating a new Ancillary Service Region, it will conduct an analysis to determine whether the adjustments being considered create market power issues in either the new Ancillary Service Regions being considered or the pre-existing Ancillary Service Regions. The CAISO’s analysis will be included in the stakeholder process and stakeholders will be able to comment on any new market mitigation measures proposed for the CAISO’s procurement of Ancillary Services prior to any tariff amendment filing.

4.2 Ancillary Services Requirements

The requirements for AS are determined by CAISO in accordance with the WECC Minimum Operating Reliability Criteria (MORC) and NERC guidelines.

AS Bids from resources internal to the CAISO Control Area do not compete for the use of the transmission network in the market optimization applications. Rather, AS is procured on a regional basis, where the AS Region is defined as a set of PNodes, including Scheduling Points, on the FNM. Minimum and maximum procurement limits are set for each AS Region, for each service, and for each hour, to ensure Local Reliability Criteria are met.

Accordingly, CAISO establishes minimum AS requirements for the “Expanded System Region”, for each AS type, taking into consideration:

- Hydro-thermal Supply resource proportions
- Path Contingency deratings
- Path Operating Transfer Capability (OTC)
- Largest single Contingency (on-line Generating Unit)

CAISO may establish minimum and/or maximum AS procurement limits for each AS Region, taking into consideration one or more of the following factors:

- Hydro versus thermal Supply resource proportions
- Path Contingency deratings
- Path OTCs
- Largest single Contingency (on-line Generating Unit or in-service transmission)
- Forecasted path flows
- Other anticipated local operating conditions for Load and/or Generation pocket AS Regions

The minimum AS limit for the Expanded System Region reflects the quantities of each Ancillary Service required to meet the WECC and NERC requirements for the CAISO Control Area

The minimum procurement limit for AS in the System Region, which is defined as the Expanded System Region minus the System Resource at Scheduling Points, is set to a proportion of the minimum procurement limits of the Expanded System Region. The current default is 50%, which may be changed based on system conditions and CAISO Operator decision. CAISO posts the percentage of procurement limit from imports.

In addition to the System and Expanded System Regions, the procurement limit(s) for any given AS Region may be:

- **Zero (or infinity for maximum limit)** – Indicating that there are no expected limitations, associated with the transmission path(s) adjoining the AS Region to other AS Regions, on the deliverability of AS procured system-wide; or
- **Non-zero** – Such a limit is based on factors that have a direct affect on the system constraint for which the AS Region was intended to manage.

For a given AS Region in a given interval, if the maximum total upward AS limit is set to a value less than the sum of the minimum limits for individual upward AS types, then the maximum total upward AS limit will be relaxed, if necessary, to uphold the minimum procurement limits for individual AS types. Otherwise, the total upward AS limit can bind simultaneous with binding minimum limits for individual upward AS types.

The following factors are considered by CAISO to establish a minimum or maximum limit for each AS sub-Region :

- The CAISO Forecasts of CAISO Demand
- The location of Demand within the Control Area
- Information regarding network and resource operating constraints that affect the deliverability of AS into or out of a AS sub-Region
- The locational mix of generating resources
- Generating resource outages
- Historical patterns of transmission and generating resource availability
- Regional transmission limitations and constraints
- Transmission outages
- Available Transfer Capacity
- Day-Ahead Schedules or HASP Intertie Schedules
- Whether any Ancillary Services provided from System Resources requiring a NERC tag fail to have a NERC tag
- Other factors affecting system reliability

The determination of a sub-Regional minimum procurement related to a transmission outage is based on the N-1 OTC of the path minus the expected N-0 flow on the path, where the expected N-0 flow on the path is determined from previous market solutions for similar conditions. The N-

1 OTC of the path is the effective OTC of the path when the single largest Contingency is taken on an element of that path.

For example, consider a path that is comprised of three transmission lines, and has a normal OTC of 1000 MW. For a particular hour of the next day's market, the expected flow is 800 MW, which is below the N-0 OTC. However, if the system experiences a loss of one of the lines that comprise this path, the N-1 OTC of the path is de-rated to 500 MW. Therefore, the impact of supplying Energy to CAISO Demand for an N-1 Contingency on this path is 300 MW, since the 800 MW of N-0 flow must be reduced to 500 MW for that Outage.

4.2.1 Self-Provided Ancillary Services

This is based on CAISO Tariff Section 8.6.2.

As stated in the overview, Generating Units and Participating Loads certified for AS may submit Submissions to Self-Provide an AS in the IFM. Self-Provided AS effectively reduces the AS requirements that need to be met by AS Bids within the same AS Region, and reduces the AS Obligation for the SC Self-Providing the AS, in the AS cost allocation.

Qualification of Submissions to Self-Provide AS is performed in a two step process:

4.2.1.1 Pre-MPM/RRD Qualification

Before the market optimization is performed, the CAISO qualifies all Submissions to Self-Provide AS with respect to (i) resource certification to provide the requested Self-Provided AS, (ii) feasibility with respect to the Resource capacity limits, (iii) feasibility with respect to the relevant Resource ramp rate limits, and (iv) total self provision from all Resources with respect to (a) the Expanded System Region total AS requirements, or (b) any maximum Regional procurement Limit. These pre-MPM/RRD qualifications are performed for each AS type separately.

For item (iv) above, If the total Submissions to Self-Provide an AS exceeds the maximum System Region and regional requirement for the relevant AS in an AS Region, then Self-Provided AS is pre-qualified pro-rata with respect to their Submissions to Self-Provide AS. When there are over-lapping AS Regions defined, CAISO enforces a priority order on the AS Regions for the pro-rata qualification processing. Finally, after all regional requirements are enforced for determination of pre-qualified Self-Provided of AS, the System requirements are enforced to ensure that the total qualified Self-Provided AS does not exceed the System Region AS requirements.

- This priority order only applies to the qualification of Self-Provided AS in an AS Region where a maximum AS procurement limit is specified. Unlike minimum AS Region procurement limits, which are specified for each AS type individually, a maximum procurement limit is enforced on all upward AS types in the AS Region collectively not to exceed the System Region AS requirements.
- Therefore, when the maximum procurement limit is reached within an AS Region due to over-supply of self-provision of upward AS, these self-provision schedules are disqualified on a pro-rata bases starting with the lowest priority AS types. The hierarchy of valuing AS types, from highest to lowest, is as follows:
 - Regulation Up
 - Spinning Reserve
 - Non-Spinning Reserve

4.2.1.2 Final Qualification Process

After the pre-MPM/RRD qualification process is complete, a second phase of Self-Provided Ancillary Services (SPAS) qualification takes place internal to the market optimization (IFM in Day-Ahead, or RTUC in Real Time). The purpose of this second phase of qualification is to determine if any of the initially qualified SPAS (from the pre-MPM/RRD qualification process) for RA Resources is needed for Energy. If the market optimization determines that capacity submitted as SPAS for an RA Resource is needed as Energy to resolve transmission constraints and/or satisfy the energy balance constraint (i.e., solve problem locally before looking at larger LAP Load reductions), then such Self Provided AS capacity is partially or entirely disqualified.

For the Day-Ahead process, this is performed in the MPM-RRD process, thus the Energy balance constraint pertains to the CFCD, not the bid-in Demand considered in the IFM run. For the Real Time process, this is performed in RTUC, which is also based on the CFCD.

Key in this determination is identifying all Resources that are subject to the second phase of the qualification. For this purpose, a special designation flag is maintained in the CAISO Master File and sent to market applications to indicate whether a resource is subject to the optimized qualification of SPAS. This flag shall be set to “YES” for all resources with an offer obligation pursuant to a contractual or tariff obligation (Resource Adequacy Resource (RAR) or an RMR Unit). For release 1 of MRTU, this flag is not market specific, nor is it capacity specific. This flag, hereafter referred to as the SPAS Optimization flag, shall apply to all the capacity of a resource for all markets.

Based on the SPAS Optimization flag value, and the results of the pre-MPM/RRD qualification process, all SPAS capacity is labeled as one of the following for consideration in the final qualification process:

- For SPAS Optimization Flag “NO” resources, SPAS capacity qualified in the pre-MPM/RRD qualification process is considered unconditionally qualified, or simply *qualified*.
- For SPAS Optimization Flag “YES” resources, SPAS capacity qualified in the pre-MPM/RRD qualification process is considered *conditionally qualified*
- Regardless of the SPAS Optimization Flag, SPAS capacity unqualified in the pre-MPM/RRD qualification process is considered conditionally unqualified

4.2.1.2.1 Qualified SPAS

All SPAS capacity classified as *qualified* for the final SPAS qualification process undergoes no further qualification processing and this capacity is not converted to Energy in the market optimization

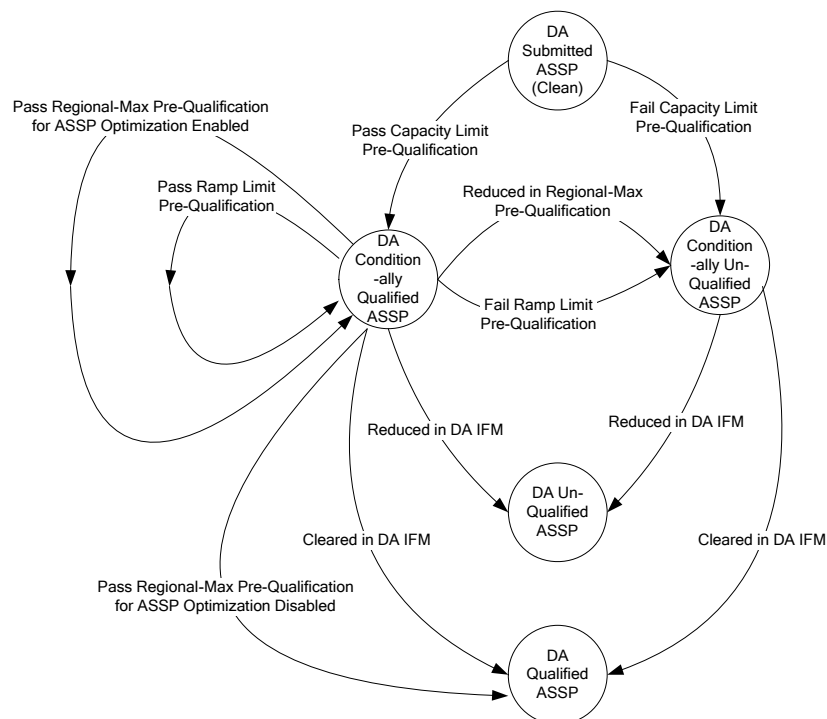
4.2.1.2.2 Conditionally Qualified SPAS

All SPAS capacity classified as *conditionally qualified* for the final SPAS qualification process may be converted to Energy to resolve transmission constraints and/or satisfy the Energy balance constraint. Such capacity is not converted to Energy unless all Economic Energy Bids are exhausted to meet these constraints, but is converted before other Self-Schedules are adjusted.

4.2.1.2.3 Conditionally Unqualified SPAS

All SPAS capacity classified as *conditionally unqualified* for the final SPAS qualification process may be converted to *qualified* SPAS. If SPAS was unqualified in the pre-MPM/RRD qualification process due to excess SPAS from all resources for a given AS Region, capacity classified as *conditionally qualified* on a resource that is converted to Energy in the final qualification process creates an opportunity to re-evaluate the ability to qualify a greater proportion of SPAS from other Resources in that same AS Region.

Exhibit 4-2: Qualification Process of Submissions to Self-Provide an AS



4.2.2 Conversion of Conditionally Qualified SPAS to Energy

For the purpose of optimally converting *conditionally qualified* SPAS to Energy, a multi-segment Bid Curve is generated for each resource for consideration in the AS procurement optimization.

The most simplistic case is where a resource only provides Economic AS Bids, with no SPAS. In this case, the AS Bid is not modified for conversion of AS to Energy.

In the case where capacity from an SPAS Optimization flag “NO” Resource is *qualified* in the pre-MPM/RRD qualification process, then this capacity is not represented by any AS Bid segment, and therefore cannot be converted to Energy.

In the case where a SPAS Optimization flag “YES” Resource is *conditionally qualified* in the pre-MPM/RRD qualification process, then this capacity is assigned a penalty price P1 Bid segment, which is an artificially set at a negative price, P1, such that this capacity is cleared as AS in the market optimization before any other positive priced Economic Bids are cleared. This enables the optimization software to effectively apply a priority to the *conditionally qualified* SPAS over economically priced AS, but also allows the optimization to recognize this capacity as less economical compared to the penalty price associated with binding transmission constraints or

satisfying the Energy balance constraint. That is, if a transmission constraint becomes binding, the optimization attempts to dispatch Energy from all effective resources with Economic Energy Bids optimally to resolve the constraint. If all such Economic Bids are exhausted and the constraint still exists, then the optimization naturally finds the most optimal solution is to not clear the minimal portion of the *conditionally qualified* SPAS so that just enough Energy can be dispatched on that resource to relieve the constraint. This process effectively optimally determines exactly how much of the *conditionally qualified* SPAS can ultimately be *qualified*.

4.2.3 Conversion of Conditionally Unqualified SPAS to Qualified SPAS

In the same process of optimally converting *conditionally qualified* SPAS to energy, a second penalty priced AS Bid Curve segment is inserted to represent the amount of unqualified SPAS determined in the pre-MPM/RRD qualification process, regardless of the SPAS Optimization flag indication. This penalty price Bid segment is administratively set to a smaller penalty price than for the *conditionally qualified* SPAS described above.

The purpose of classifying unqualified SPAS from the pre-MPM/RRD qualification process as *conditionally unqualified* is to allow this unqualified SPAS to be “re-qualified” if (i) it was originally unqualified because of a surplus of total SPAS for a given AS Region, and (ii) *conditionally qualified* SPAS on Resources in that AS Region was converted to Energy in the final qualification process.

Because the penalty price Bid segment for *conditionally unqualified* SPAS is priced higher than the *conditionally qualified* SPAS for all resources (a smaller negative penalty price), it is cleared as qualified SPAS after all conditionally qualified SPAS Bid segments are cleared, and before Economic AS bids are cleared.

This process effectively maximizes the qualification of SPAS, accounting for the optimal conversion of SPAS to Energy as necessary on such obligated resources

4.2.4 Other Details of SPAS

- The classification of SPAS resulting from the pre-MPM/RRD qualification process is transparent to the SC of affected Resources. Final qualification of all SPAS is reported in the publishing of IFM results, which are the end-state of the multi-step qualification process. No information is published regarding the *conditionally qualified* or *conditionally unqualified* capacities, or the *conditionally qualified* SPAS that may have been converted to Energy in the final qualification process
- Self-Provided resources designated as Contingency Only are only called in the event of a Contingency, where the Contingency Flag is for the whole day. The Contingency Only

designation is only applicable to real-time dispatch and does not effect the co-optimization of Energy and Ancillary Service in the Day-Ahead IFM.

- Self-provision of AS is not allowed from System Resources, since the cost of transmission Congestion must be considered in the Energy and AS co-optimization. System Resources can bid down to the “Bid floor” (\$0/MWh) to ensure that they are scheduled as Price Takers.
- Resources may Self-Provide AS and bid in the AS market for the same service for the same hour in the same market.

4.2.5 Ancillary Service Award Allocation of Energy Bids

This section is based on the CAISO Tariff Section 30.7.

The market optimization applications requires an Energy Bid to be able to Dispatch any Operating Reserve awards in the RTM, irrespective of whether these awards are from qualified self-provision or accepted AS Bids, and whether they are awarded in the IFM, HASP, or RTUC. To effectively reserve contingent Operating Reserve from Dispatch, the RTM applications need to determine the portion of the Energy Bid that corresponds to that service so that its price is replaced with the appropriate penalty price.

Furthermore, the AS allocation on the Energy Bid is required for ex post Instructed Imbalance Energy calculation, which is by service and Energy Bid segment. This information is used in the Bid Cost Recovery and No Pay mechanisms.

Each RTM application retrieves updated Outage information from SLIC at each Dispatch time and then allocates each Ancillary Service Award onto the Energy Bid as follows:

- If the resource provides Regulation Up, the capacity portion equal to the Regulation Up AS Award just below the upper regulating limit or the upper operating limit (considering derates), whichever is lower, is reserved for Regulation Up. In the event of a derate, the awarded Regulation Up Capacity is shifted down. If as a result, the Regulation Up AS Award overlaps with the Energy Bid, the overlapping portion of the Energy Bid is ignored. If the Regulation Up AS Award extends below the IFM Schedule (due to a derate), the Regulation Up AS Award is clipped from below to the IFM Schedule and the entire portion of the Energy Bid above the IFM Schedule is ignored.
- If the resource provides Regulation Down, the capacity portion equal to the Regulation Down AS Award just above the lower regulating limit or the lower operating limit (considering overrates), whichever is higher, is reserved for Regulation Down. If the Regulation Down AS Award overlaps with the Energy Bid, the overlapping portion of the Energy Bid is ignored. If the Regulation Down AS Award extends above the IFM

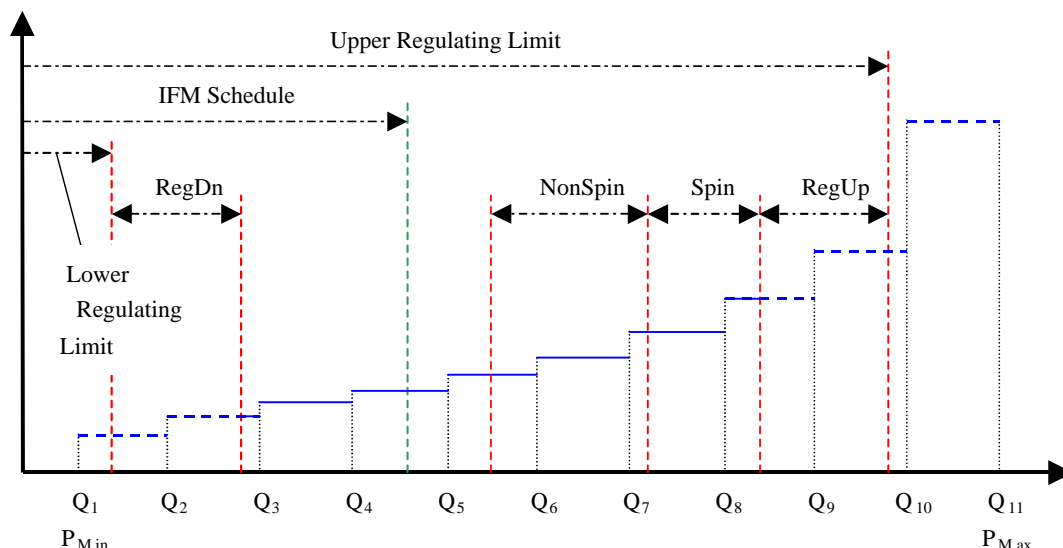
Schedule (due to an overrate), the Regulation Down AS Award is clipped from above to the IFM Schedule and the entire portion of the Energy Bid below the IFM Schedule is ignored.

- If the resource provides Spinning Reserve, the Energy Bid portion equal to the Spinning Reserve AS Award below the allocated portion for Regulation Up, if any, otherwise below the upper operating limit (considering derates), or the top of the Energy Bid, whichever lower, is reserved for Spinning Reserve. If the total Spinning Reserve AS Award extends below the IFM Schedule (due to a derate), the total Spinning Reserve AS Award is clipped from below to the IFM Schedule.
- If the resource provides Non-Spinning Reserve, the Energy Bid portion equal to the Non-Spinning Reserve AS Award below the allocated portion for Regulation Up and Spinning Reserve, if any, otherwise below the upper operating limit (considering derates), or the top of the Energy Bid, whichever is lower, is reserved for Non-Spinning Reserve. If the total Non-Spinning Reserve AS Award extends below the IFM Schedule (due to a derate), the total Non-Spinning Reserve AS Award is clipped from below to the IFM Schedule.
- The remaining portion of the Energy Bid, if any, is used for Dispatch and additional AS procurement as applicable.

A Market Participant is allowed (subject to SIBR validation) to submit and designate either “Contingency Only” or “not-Contingency Only” for Spinning and Non-Spinning Reserves, for all 24 hours, according to the following rules:

- If Spinning Reserve is designated as Contingency Only, then Non-Spinning Reserve must also be designated as Contingency Only.
- If Spinning Reserve is designated as not-Contingency Only, then Non-Spinning Reserve must also be designated as not-Contingency Only.
- There can not be a portion of the same service designated as Contingency Only and another portion of the same service designated as not-Contingency Only.
- The Contingency Flag is set for both types of AS, not for an individual service.

Exhibit 4-3 illustrates the AS Award allocation on an Energy Bid that spans the entire dispatchable capacity of a resource. Any portions of the Energy Bid for capacity allocated to Regulation Up and Regulation Down or beyond that (dashed lines in Exhibit 4-3) are ignored.

Exhibit 4-3: Ancillary Service Award Allocation on the Energy Bid

Energy Bids are required to dispatch Operating Reserve, but they are not needed for Regulation. A Regulation Up AS Award is allocated under the applicable upper regulating limit or the derated upper operating limit if lower, irrespective of whether there is an Energy Bid or not for that capacity range. Any overlapping Energy Bid portion is not used for dispatch.

Regulation is not dispatched based on its Energy Bid Curve price. Rather, Regulation is dispatched by AGC based wholly on the resource's effectiveness to re-establish the system frequency target, and taking into consideration the resource's operating constraints, such as Ramp Rate.

To the extent a resource is moved away from its Dispatch Operating Point (DOP) by AGC (i.e., it is not awarded Imbalance Energy), the Market Clearing software assumes that the resource is brought back to its DOP in the next market interval. In so doing, the net Energy delivery from the unit, both above and below its DOP, averaged over time, to zero.

However, to the extent that such a resource is sustaining an operating point above its DOP, the Energy delivered or consumed (relative to the DOP) is paid as Uninstructed Imbalance Energy.

4.2.6 Regulation Up & Down Requirements

A minimum requirement for Regulation Up capacity and a minimum requirement for Regulation Down capacity can be specified for each AS Region and each Trading Hour. In addition there is a maximum requirement for all upward AS collectively. Both Regulation Bids and Regulation self-provisions can participate in meeting these requirements. Only on-line Generating Units can

be awarded Regulation service to contribute to the Regulation Up and Regulation Down requirements.

CAISO sets its Regulation reserve target as a percentage of CAISO Forecast of CAISO Demand for the hour based upon its need to meet the WECC and NERC performance standards (primarily CPS1 and CPS2). However, the percentage targets can be different for Regulation Up and Regulation Down. The percentage targets can also vary based on the hour of the Operating Day. CAISO's Regulation targets (in MWh) may change if its Demand Forecast changes after running the Day-Ahead Market.

4.2.7 Operating Reserve Requirements

This section is based on CAISO Tariff Section 8.2.3.2.

CAISO sets its procurement target in accordance with WECC Minimum Operating Reliability Criteria (MORC) requirements. Currently, based on these standards, CAISO procures Operating Reserves equal to the greater of:

- Five percent of CAISO Forecast of CAISO Demand met by hydroelectric resources, plus seven percent of CAISO Forecast of CAISO Demand met by thermal resources plus firm exports minus firm purchases, (less net firm imports)¹⁶, or
- The single largest Contingency

In practice, the former (quantity of Operating Reserves based on percentage of CAISO Demand) is greater and sets the requirements system-wide. However, if CAISO must target procurement of Operating Reserves on a more granular basis, such as sub-AS Regions, the latter criteria (quantity of Operating Reserves based on the single largest Contingency) could drive the procurement of Operating Reserves in one or more of the smaller regions.

In addition, under the current standards, at least 50% of the Operating Reserve requirement must be met by Spinning Reserves,¹⁷ and no more than 50% of the Operating Reserve requirements may be met from imports of AS. Moreover, the quantity of AS imported from a single intertie may be limited to 25% of the total system-wide AS requirement, at the CAISO Operator's decision based on system conditions.

¹⁶ WECC MORC requirements do not directly apply to AS procurement limits placed on sub-regions of the CAISO Control Area. Minimum AS Regional procurement limits for Regions other than the Expanded System Region may not sum to the total Expanded System minimum requirement, as they specify only the portion of the total Expanded System requirement that must be procured within a specific AS Region.

¹⁷ CAISO posts a market notice in the event that the 50% Spinning Reserve requirement is to be changed.

CAISO follows these requirements or whatever other NERC or WECC standards may replace them.

Cascading is the procurement of upward AS by substituting a higher quality AS type to meet the requirement of a lower quality AS type if it is economically optimal to do so in the co-optimization process. The hierarchy of valuing AS types, from highest to lowest, is as follows:

- Regulation Up
- Spinning Reserve
- Non-Spinning Reserve

This substitution only occurs if the substituting resources are eligible to provide the lesser valuable service.

The quantities of Regulation Up, Regulation Down, and Operating Reserves that CAISO targets for each hour of the Operating Day are published as part of the public market information by 1800 hours two days prior to the Trading Day. Total system AS requirement is also posted to OASIS.

4.2.7.1 Spinning Reserve Requirements

Separate Spinning Reserve minimal requirements are specified for each AS Region and for each Trading Hour. The Spinning Reserve requirements can be met by Spinning Reserve Bids and Spinning Reserve self-provision, as well as Regulation Up Bids. Only on-line Generating Units (and eligible System Resources) provide Spinning Reserve service. According to Ancillary Service cascading, Regulation Up can be used as Spinning Reserve after the Regulation Up requirement is met. The substitution of Regulation Up self-provision for Spinning Reserve is not allowed.

When cascading methodology results in awarding Regulation Up capacity to satisfy a portion of the Spinning Reserve requirement, this capacity is not treated as Spinning Reserve. The capacity retains the Regulation Up designation. As such, the Regulation Up AS Award does not require an Energy Bid to be dispatched in Real-Time by AGC.

4.2.7.2 Non-Spinning Reserve Requirements

Separate Non-Spinning Reserve minimum requirements can be specified for each AS Region for each Trading Hour. Bids for Regulation Up and Spinning Reserve can also be counted as Non-Spinning Reserve. The Non-Spinning Reserve requirements can be met by Non-Spinning Reserve Bids and Non-Spinning Reserve self-provision as well as Regulation Up and Spinning

Reserve Bids. The cascading of Regulation Up and Spinning Reserve self-provision is not allowed.

4.2.8 Maximum Upward Capacity Constraint

The total amount of upward Ancillary Service capacity may be limited for each AS Region. Specifically, the sum of Regulation Up, Spinning Reserve, and Non-Spinning Reserve procured in each AS Region using Bids or self-provision cannot exceed a maximum capacity limit at any time interval.

The purpose of enforcing a maximum procurement limit on an AS Region is to minimize the likelihood of a condition where too much AS capacity is allocated to resources in an AS Region where Energy supply limitations, due to Transmission or other constraints, are expected.

4.3 Ancillary Services Procurement

The bidding rules for AS procurement are as follows:

- All AS Bids (not Self-Provided) may be accompanied by an Energy Bid in DAM, and must be accompanied by an Energy Bid in RTM, which are used as the AS Bid is considered in the AS selection process (which is part of the simultaneous Energy, AS, and Congestion Market Clearing process). If an AS Bid in DAM is included and the Energy Bid does not extend to the full available capacity of the resource, then all or part of the AS Bid is considered to use available capacity that is not covered by the Energy Bid, and no opportunity cost is considered in the co-optimization of Energy and AS.
- For AS that is Self-Provided in the IFM, an Energy Bid may be submitted for DAM, but must be submitted later, specifically, in the HASP/Real-Time Bid submission timeframe. Qualification of Submissions of Self-Provided AS takes place prior to IFM. While Conditionally Qualified Self-Provided AS is included in the optimization, unconditionally qualified Self-Provided AS does not enter the optimization.

The cost of procuring the AS by CAISO on behalf of the SCs is allocated to Measured Demand on a CAISO Control Area basis.

4.3.1 Ancillary Services Procurement in Day-Ahead Market

CAISO procures 100% of its AS needs associated with the CAISO Forecast of CAISO Demand net of unconditionally qualified Self-Provided AS. AS Bids are evaluated simultaneously with Energy Bids in the IFM to clear bid-in Supply and Demand. Thus, the IFM co-optimizes Energy and AS; the capacity of a resource with Energy and AS Bids is optimally used for an Energy

schedule, or it is reserved for AS in the form of AS Awards. Furthermore, AS Bids from System Resources compete with Energy Bids for Scheduling Point transmission capacity.

Supply of Energy and AS capacity from System Resources flow to CAISO Demand over radial Transmission Interfaces. Therefore, the optimal Dispatch of Energy and AS capacity can be accomplished by assigning the same Congestion cost to each commodity. This process allows Energy and AS capacity to compete for the transmission access to (or from) the CAISO Control Area directly, based on their Bids. This cannot be done for transmission internal to the CAISO Control Area because of the non-radial nature of the interconnected grid. Energy and AS capacity cannot directly compete for transmission across the internal CAISO Control Area grid.

In the optimization of Energy and AS clearing, the limits on AS Regions are enforced as constraints represented by penalty prices in the application software, while Energy and AS are economically optimized subject to the AS Region procurement constraint(s).

AS are procured in the IFM to meet the AS requirements, net of qualified AS self-provision, subject to resource operating characteristics and regional constraints.

Because awarded AS capacity must be backed up by available transmission capacity in order to transmit in case AS are dispatched for Energy, System Resources awarded AS are charged for congestion in case the AS are in the Import direction, and in the direction of the congestion. If there is congestion in the export direction (e.g., the opposite direction to the awarded AS), no credit is given due to the fact that AS capacity does not provide a physical counterflow and does not relieve the congestion.

4.3.2 Ancillary Services Procurement in Real-Time Market

AS are procured in the Real-Time Market, as needed to satisfy the MORC requirements. In HASP, AS needed to meet system requirements may be procured from System Resources. In RTUC, AS may be procured from resources internal to the CAISO system. Note, this is not a sequential procurement process. HASP is performed 75 minutes before each hour, during which Bids from both:

- System Resources and
- Internal resources are optimized

The distinction between AS Awards on System Resources and internal resources in HASP and RTUC is that with System Resources, the AS Awards are issued 45 minutes before the Operating Hour and are constant for the entire hour. AS Awards for internal resources and Dynamic System Resources are only considered binding the first 15-minute interval of each RTUC run including the RTUC run supporting HASP. The resources that are either already

committed or that must be committed in Real-Time to provide AS are eligible for Start-Up and Minimum Load Cost compensation.

Additional AS are procured in Real-Time only from resources that are certified to provide these services.

Refer to Section 7.6.1.2, Real-Time Ancillary Services Procurement, for additional information.

4.3.2.1 Regulation

Procurement of additional Regulation is automated. WSCC allows Regulation to be used for Spinning Reserve. Although Regulation Up won't necessarily be used as spin, it does count to ensure that there are sufficient Operating Reserves available.

4.3.2.2 Spinning & Non-Spinning Reserve

This section is based on CAISO Tariff Section 31.5.6.

Real-Time procurement and pricing of Spinning Reserve and Non-Spinning Reserve is performed using dynamic co-optimization of Energy and Spinning and Non-Spinning Reserve. Spinning Reserve and Non-Spinning Reserve procured in Real-Time are for Contingency Only.

These requirements are calculated as part of the RTM based on the Demand Forecast and can be adjusted by the CAISO Operator.

4.4 Ancillary Services Marginal Prices

Generally speaking, the Ancillary Services Marginal Price (ASMP) for a given service at a given "location" is the cost of procuring an increment (MW) of that service at that location. It is, however, understood that the use of the word "location" here is not entirely precise because the "locations" where AS requirements are defined are AS Regions, whereas ASMPs are determined for individual PNodes.

This is a somewhat academic distinction, however, because in practice all PNodes belonging to the same set of AS Regions have the same ASMP. To better understand this statement, consider the AS Expanded System Region along with all of the AS Regions. Because some AS Regions have common areas (are nested), collectively they divide up the AS Expanded System Region into smaller areas. The ASMP for all PNodes within each of these smaller areas is the same.

ASMPs can be described more precisely in terms of Regional Ancillary Service Shadow Prices (RASSPs). RASSPs are produced as a result of the co-optimization of Energy and AS for each

AS Region, and represent the cost sensitivity of the relevant binding regional constraint at the optimal solution, i.e., the marginal reduction of the combined Energy-AS procurement cost associated with a marginal relaxation of that constraint.

The opportunity cost for a resource which is awarded AS rather than energy when the energy bid is otherwise competitive is not computed explicitly, rather it is implicit in RASSP for that AS Region.

If neither of the constraints (upper or lower bound) is binding for an AS Region, then the corresponding RASSP is zero. The ASMP for a given service at a particular PNode is the sum of all RASSPs for that service over all AS Regions that include that PNode. It thus follows that all PNodes located in exactly the same set of AS Regions have the same ASMP. For example, if the defined AS Regions with non-zero RASSPs consist of "South of Path 26", the System Region, the Scheduling Points, and the Expanded System Region, then all resources within "South of Path 26" have the same ASMP.

Exhibit 4-4 presents an example of how the RASSPs and ASMPs are related for a given set of the AS Regions. In this example the RASSPs are "given" from a scheduling run for a specific AS product. The resulting ASMPs are for the PNodes within each AS Region.

Exhibit 4-4: Example for Spinning Reserve AS

AS Region	RASSP (Given)	ASMP @ PNode
South of Path 26	\$20/ MW	$20 + 10 + 5 =$ \$35/MWh
System	\$10/ MW	$10 + 5 =$ \$15/MWh
Expanded System	\$5/ MW	\$5/MWh

The ASMPs computed at each PNode for each service are not lower than the highest accepted AS Bid for that service from any resource at that PNode. In fact, the ASMP also reflects any lost opportunity costs associated with keeping the resource capacity unloaded for AS instead of scheduling that capacity as Energy in the same market.

4.5 Ancillary Services Considerations

This section identifies important considerations in the use and procurement of Ancillary Services, including:

- The Operating Reserve Ramp Rate for Energy within the AS capacity is a single Ramp Rate, which is distinct from the Operational Ramp Rate, and is the same for Spinning and Non-Spinning Reserve.

- Energy Limits of resources bidding into the AS market can be managed by the use of the Contingency Only designation supplied by the SC in the AS Bid. The Contingency Only designation applies for the entire Trading Day. In Real-Time, Energy from Contingency Only Operating Reserves is only cleared against Demand only under Contingency situations.
- Day-Ahead SC trades of Ancillary Service Obligations are supported, however, physical trades of Ancillary Services capacity is not.
- Effect of Forbidden Operating Regions
- Ramp Rate restrictions (cross hour Ramping; Regulation Ramping)
- Bids to export AS are not supported in the CAISO Markets
- Export of on-demand obligations of AS are manually supported but cannot be procured from the DAM or RTM.
- Any AS designated as Contingency Only is not normally dispatched as Energy in the normal RTED mode. In the Real Time Contingent Dispatch (RTCD) mode, Energy behind Contingency Only AS and non-Contingency Only AS is not distinguished, and are dispatched economically.
- Contingency Only can be dispatched in the event that all Imbalance Energy Bids have been exhausted and Demand cannot be cleared without violating security constraints. This action is performed by RTED, subject to CAISO Operator approval. The Energy behind Contingency-Only AS bids is dispatched before relaxing security constraints.

4.6 Ancillary Services Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements, and Section 8.4, Technical Requirements for Providing Ancillary Services

Each Generating Unit, System Unit, or Load that is allowed to submit a Bid or AS self-provision under the CAISO Tariff, and each System Resource that is allowed to submit a Bid to provide AS under the CAISO Tariff, must comply with CAISO's certification and testing requirements as contained in the *BPM for Compliance Monitoring*.

CAISO has the right to inspect Generating Units, Participating Loads, or the individual resources comprising System Units and other equipment for the purposes of the issue of a certificate and periodically thereafter to satisfy itself that the technical requirements continue to be met. If at

any time CAISO's technical requirements are not being met, CAISO may withdraw the certificate for the Generating Unit, System Unit, Participating Load, or System Resource concerned.¹⁸

The AS certification and the associated maximum AS capacity are registered in the Master File after testing that demonstrates satisfactory delivery of each AS.

4.6.1 Regulation Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.1.1, Regulation

Each Generating Unit and System Unit that submits a Bid Regulation or Self-Provides Regulation must be certified and tested by CAISO using the process defined in Part A of Appendix K of the CAISO Tariff. Each Dynamic System Resource offering Regulation must comply with the Dynamic Scheduling Protocol in Appendix X of the CAISO Tariff.

Generating Units with Automatic Generation Control capability may be certified for Regulation Up and Regulation Down. Their maximum Regulation Up and Regulation Down capacity is limited to their widest Regulation range, or their 10-minute Ramping capability with their best Regulation Ramp Rate, whichever is lower.

Resource-specific System Resources may also be certified for Regulation Up and Regulation Down. Such units must have AGC and dynamic interchange capability to provide Regulation.

4.6.2 Spinning Reserve Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.3(a), Ancillary Service Capability Standards

Spinning Reserve may be provided only from Generating Units and System Resources that submit Bids to provide Spinning Reserve from imports, or System Units, which are certified and tested by CAISO using the process defined in Appendix K of the CAISO Tariff.

Dispatchable Generating Units may be certified for Spinning Reserve if they can respond to five-minute Dispatch Instructions and can sustain Energy delivery associated with a Spinning Reserve Award for at least two hours. Their maximum Spinning Reserve capacity is limited to

¹⁸ Participating Generators, Participating Loads and Dynamically-Scheduled System Resources are governed by pro-forma Agreements that are included as Appendix B of the Tariff. Each of these Agreements has a Termination clause that permits cancellation of the Agreement under certain conditions, including failure to meet technical requirements. See, for example, Section 3.2.1 of the Participating Generator Agreement.

their operating range from Minimum Load to maximum capacity, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is lower.

System Resources may be certified for Spinning Reserve if they can respond to five-minute Dispatch Instructions and can sustain Energy delivery associated with a Spinning Reserve Award for at least two hours.

4.6.3 Non-Spinning Reserve Certification & Testing Requirements

This section is based on CAISO Tariff Section 8.3.4, Certification and Testing Requirements and Section 8.4.3(a), Ancillary Service Capability Standards

Non-Spinning Reserve may be provided from Participating Loads, Curtailable Demand which can be reduced by Dispatch, interruptible exports, on-demand rights from other entities or Control Areas, Generating Units, System Resources that submit Bids to provide Non-Spinning Reserve from imports, or System Units, which have been certified and tested by CAISO using the process defined in – Parts C of Appendix K of the CAISO Tariff, respectively.

Generating Units may be certified for Non-Spinning Reserve if they can respond to five-minute Dispatch Instructions and can sustain Energy delivery associated with a Non-Spinning Reserve Award for at least two hours.

- The maximum Non-Spinning Reserve capacity for Fast Start Units that can start and synchronize with the grid within 10 minutes are limited to the output level they can reach from offline status in 10 minutes, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is higher, but not greater than their maximum capacity.
- The maximum Non-Spinning Reserve capacity for other resources that cannot start and synchronize with the grid within 10 minutes are limited to their operating range from Minimum Load to maximum capacity, or their 10-minute Ramping capability with their best Operational Ramp Rate, whichever is lower. In the IFM, Non-Spinning Reserve can be procured from all on-line resources (whether self-committed or committed in the IFM) and from offline Fast Start Units.

Only units whose technical characteristics allow them to deliver Non-Spinning Reserve Award within 10 minutes may submit a Bid Non-Spinning Reserve into RTM.

Units that are already on-line may also offer Non-Spinning Reserve, provided that they are otherwise eligible.

Participating Load resources may be certified for Non-Spinning Reserve if they can respond to five-minute Dispatch Instructions and can sustain reduced Energy consumption associated with a Non-Spinning Reserve Award for at least two hours.

System Resources may be certified for Non-Spinning Reserve if they can respond to five-minute Dispatch Instructions and can sustain Energy delivery associated with a Non-Spinning Reserve Award for at least two hours.