• Summary of Motions and Action Items •

**Agenda Item 3—Consent Agenda**— Motion by Mo Awad (Westar) seconded by Tom Hestermann (Sunflower) to approve the consent agenda. The motion passed.

**Agenda Item 8a—RR 268 (OCRTF Revisions to Operating Criteria Sections 1, 2, and 3)**—Motion by Tom Hestermann (Sunflower) seconded by Mo Awad (Westar) to approve RR 268 as modified. The motion passed.

**Agenda Item 8b—RR 269 (OCRTF Revisions to Operating Criteria Sections 4 and 8)**—Motion by Tom Hestermann (Sunflower) seconded by Bernie Liu (Xcel) to approve RR 269 as modified. The motion passed.

**Agenda Item 8c—RR 270 (OCRTF Revisions to Operating Criteria Appendices)**—Motion by Jessica Meyer (LES) seconded by Jim Bixby (ITC) to approve RR 270 as modified. The motion passed.

**Agenda Item 9b—RR 259 (Settlements Statements Timelines)**—Motion by Jessica Meyer (LES) seconded by Jim Bixby (ITC) to approve RTWG comments on RR 259 as modified. The motion passed.

**Agenda Item 9c—RR 252 (OOME Enhancement)**—Motion by Steve Sanders (WAPA) seconded by Bernie Liu (Xcel) to approve RR 252. The motion passed with one abstaining (Westar).

**Agenda Item 12—RR 267 (Stand-Alone Evaluation Removal from DISIS GI Study)**—Motion by Bernie Liu (Xcel) seconded by Mo Awad (Westar) to approve RR 267. The motion passed.
Southwest Power Pool
REGIONAL TARIFF WORKING GROUP MEETING
February 22, 2018
Renaissance Tower – Dallas, Texas

• M I N U T E S •

Agenda Item 1 – Administrative Items
SPP Vice Chair Robert Pick (NPPD) called the meeting to order at 8:30. The following members were in attendance or represented by proxy:

David Kays  Oklahoma Gas & Electric Company
Robert Pick  Nebraska Public Power District
Mo Awad  Westar Energy
Michael Billinger  Midwest Energy Inc.
James Bixby  ITC Great Plains, LLC
Alfred Busbee  GDS Associates/East Texas Electric Cooperatives
Tom Christensen  Basin Electric Power Cooperative
Jack Clark  NextEra Energy Resources
Alex Dobson  Oklahoma Municipal Power Authority
Greg Garst  Omaha Public Power District
Joel Hendrickson  Tri-State Generation and Transmission
Tom Hestermann  Sunflower Electric Power Corporation
Bernie Liu  Xcel Energy
Brandon McCracken  Western Farmers Electric Cooperative
Jessica Meyer  Lincoln Electric System
Robert Pennybaker  American Electric Power
Drew Robinson  Kansas City Power & Light
Neil Rowland  Kansas Municipal Energy Agency
Steve Sanders  Western Area Power Administration – UGPR
Robert Shields  Arkansas Electric Cooperative Corporation
Heather Starnes  Healy Law Offices/Missouri Joint Municipal Electric Utility Commission
John Stephens  City Utilities of Springfield
Robert Stillwell  City of Independence
John Varnell  Tenaska Power Services Company

(Attachment 1a – 2018 02 22 RTWG In Person Attendance)
(Attachment 1b – 2018 02 22 RTWG WebEx Attendance)

Agenda Item 2 – Review of Past Action Items
Marisa Choate (SPP) stated that there were no updates to existing action items and no new action items.

Agenda Item 3 – Consent Agenda (Approval Item)
Robert Pick (NPPD) presented the consent agenda which consisted of the January 25, 2018 minutes. Motion by Mo Awad (Westar) seconded by Tom Hestermann (Sunflower) to approve the consent agenda. The motion passed.
**Agenda Item 4 – RTWG Task Force Updates – CPTF & BDTF**

There were no new updates for either of the two RTWG task forces.

**Agenda Item 5 – RRR Update**

Denise Martin (SPP) provided the RRR update. January – March 2018 will be reposted due to load updates and a Z2 payoff. April 2018 will be updated for the annual updates for City of Springfield and Northwestern.

**Agenda Item 6 – Settlements Update**

Steve Davis (SPP) provided a settlements update and reminded the group to consult the settlements calendar for the dates of forthcoming resettlements.

**Agenda Item 7 – Charter Review**

The group reviewed charter language regarding “Representation” and proposed edits to address a balanced membership. Action was deferred until the March 22, 2018 meeting.  *(Attachment 2 – RTWG Charter - 2018 02 22 RTWG)*

**Agenda Item 8 – OCRTF RRs**

a. **RR 268 – OCRTF Revisions to Operating Criteria Sections 1, 2, and 3 (Approval Item)**

   Neil Robertson (SPP) presented a revision request drafted by the Operating Criteria Review Task Force to update language in the SPP Operating Criteria that is redundant with NERC Standards or is out of date with current processes. This revision request addresses sections 1, 2, and 3. The group asked questions and suggested additional changes. **Motion by Tom Hestermann (Sunflower) seconded by Mo Awad (Westar) to approve RR 268 as modified. The motion passed.** *(Attachment 3 – RR 268 RTWG Comments 2018 02 22)*

b. **RR 269 – OCRTF Revisions to Operating Criteria Sections 4 and 8 (Approval Item)**

   Neil Robertson (SPP) presented a revision request drafted by the Operating Criteria Review Task Force to update language in the SPP Operating Criteria that is redundant with NERC Standards or is out of date with current processes. This revision request addresses sections 4 and 8. The group asked questions and suggested additional changes. **Motion by Tom Hestermann (Sunflower) seconded by Bernie Liu (Xcel) to approve RR 269 as modified. The motion passed.** *(Attachment 4 – RR 269 RTWG Comments 2018 02 22)*

c. **RR 270 – OCRTF Revisions to Operating Criteria Appendices (Approval Item)**

   Neil Robertson (SPP) presented a revision request drafted by the Operating Criteria Review Task Force to update language in the SPP Operating Criteria that is redundant with NERC Standards or is out of date with current processes. This revision request addresses the appendices and proposes a stand-alone document, ‘SPP Reliability Coordinator Outage Coordination Methodology’, using the current content of Appendix OP-2 as the basis. The group asked questions and suggested additional changes. **Motion by Jessica Meyer (LES) seconded by Jim Bixby (ITC) to approve RR 270 as modified. The motion passed.** *(Attachment 5 – RR 270 RTWG Comments 2018 02 22)*
Agenda Item 9 – Market RRs

a. RR 177 – Remove Reference to NERC Standards (Approval Item)
   This RR was tabled until a future meeting due to the proper materials not being provided to the RTWG within the specified timeframe for review.

b. RR 259 – Settlements Statements Timelines (Approval Item)
   John Luallen (SPP) reintroduced a revision request to change to the market settlement posting and dispute timelines to be implemented with the new settlement system, with the goal of decreasing the amount of manual processes as a result of meter and Bilateral Settlement Schedules revisions and reducing the number of Resettlement postings. The group continued to review its draft comments from the January 25, 2018 meeting and made additional changes. The group voted to approve the revisions and consequently formally submit the RTWG comments through the revision request process. **Motion by Jessica Meyer (LES) seconded by Jim Bixby (ITC) to approve RTWG comments on RR 259 as modified. The motion passed.** (Attachment 6 – RR 259 RTWG Comments 2018 02 22)

c. RR 252 – OOME Enhancement (Approval Item)
   Raleigh Mohr (SPP) and John Luallen (SPP) presented a revision request to allow SPP the option to assign an Out-of-Merit Energy (OOME) cap and/or floor. The change will allow Resources operating under an OOME cap and/or floor to be economically dispatched up to and including the newly defined OOME limits. **Motion by Steve Sanders (WAPA) seconded by Bernie Liu (Xcel) to approve RR 252. The motion passed with one abstaining (Westar).** (Attachment 7 – RR 252 Recommendation Report)

Agenda Item 10 – 10-Year ATRR Forecast

Gayle Freier (SPP) presented the 10-year Annual Transmission Revenue Requirement (ATRR) forecast update, a biannual product that assists members in their budgeting process. The changes from the August 2017 update include zonal ATRR – Legacy – Attachment H Column 3 amounts were updated and included per the January 2018 RRR file, load ratio shares were updated through January 2018, project costs were updated to 4Q2017 project tracking data, and net plant carrying charges were updated per formula rate template filings.

Agenda Item 11 – RRR File Improvements

Nicole Wagner (SPP) provided information on a member facing project to improve processes surrounding the Rates, Requirements and Rates (RRR) file. The project aims to improve productivity and quality by reducing risk from manual tasks involved in processing Transmission Owner data and the data entry from the RRR file for Settlements by eliminating the manual spreadsheet and moving to an IT-based solution. The group asked questions and expressed concern that not having the formulas will result in the loss of an auditing tool and hamper the ability to reconcile the data. This member facing project is targeting production in September 2018.

Agenda Item 12 – RR 267 – Stand-Alone Evaluation Removal from DISIS GI Study

Steve Purdy (SPP) presented a revision request to eliminate the “Stand-Alone Scenario” from the DISIS process. The GI request queue is overwhelmed with more requests than can be accommodated within required Tariff timeline using current resources and procedures. By eliminating the “Stand-Alone Scenario”, which considers each Interconnection Request by itself, a significant amount of work will be eliminated which will free SPP’s resources to focus on the cluster study results which are the binding results. This will also permit study results to be available earlier than they currently are. To compensate for the elimination of this provision, SPP will make the stand alone equivalent study models available
earlier in the study process to customers or their agents through the existing confidentiality provisions so that they may conduct a “stand-alone scenario” of their own, if desired. The model timing is not defined in the Tariff, but will be incorporated into internal study procedures. **Motion by Bernie Liu (Xcel) seconded by Mo Awad (Westar) to approve RR 267. The motion passed.** (Attachment 8 – RR 267 Recommendation Report)

**Agenda Item 13 – Working Group Survey**
Marisa Choate (SPP) provided the QR code and link for this month’s survey and it will also be include in the recap email that is sent on Friday.

**Agenda Item 14 – Review of Motions, Action Items, and Future Meetings**
Marisa Choate (SPP) indicated that a summary of motions and action items would be disseminated to the group on Friday. The conference calls scheduled for MWTG matters on March 8, 2018 (8:30 a.m. – 2:30 p.m.) and March 15, 2018 (8:30 a.m. – 2:30 p.m.) were canceled and replaced with a meeting on March 21, 2018 in Dallas, TX (12:30 p.m. – 5:00 p.m.). The next scheduled RTWG meeting is March 22, 2018 in Dallas, TX (8:30 a.m. – 2:30 p.m.).

Respectfully Submitted,

Marisa Choate
Secretary

Attachments
(Attachment 1a – 2018 02 22 RTWG In Person Attendance)
(Attachment 1b – 2018 02 22 RTWG WebEx Attendance)
(Attachment 2 – RTWG Charter - 2018 02 22 RTWG)
(Attachment 3 – RR 268 RTWG Comments 2018 02 22)
(Attachment 4 – RR 269 RTWG Comments 2018 02 22)
(Attachment 5 – RR 270 RTWG Comments 2018 02 22)
(Attachment 6 – RR 259 RTWG Comments 2018 02 22)
(Attachment 7 – RR 252 Recommendation Report)
(Attachment 8 – RR 267 Recommendation Report)
### Attendance List

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<tr>
<th>Name</th>
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<td>John Varnell – Member</td>
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Southwest Power Pool, Inc.
Regional Tariff Working Group
Charter
January 22, 2015

PURPOSE

The Regional Tariff Working Group (RTWG) is responsible for development, recommendation, overall implementation and oversight of SPP’s Open Access Transmission Tariff (Tariff). The RTWG will further advise the SPP Staff on regulatory or implementation issues not specifically covered by the Tariff or issues where there may be conflict or differing interpretations of the Tariff. The RTWG provides policy input to the Markets and Operations Policy Committee (MOPC) and Board of Directors (BOD) and its committees, if requested.

SCOPE OF ACTIVITIES

In carrying out its purposes, the RTWG will:

1. Review and recommend language changes as necessary related to Tariff issues, service, cost recovery, cost allocation, seams agreements, review customers complaints, regulatory filings and interventions.

2. Advise and direct SPP Staff on Tariff related issues and facilitate decisions on matters which need immediate attention.

3. Identify Tariff enhancing modifications and recommend any such modifications for regulatory filings and coordinate with other Working Groups, RSC Cost Allocation Working Group (CAWG) and special task forces whose areas of responsibility will be affected by the development of tariff language and responses to regulatory requirements.

4. Identify areas where specific business practices need to be developed to guide Staff’s implementation and work with the Business Practice Working Group in the development of those practices.

5. Advise SPP Staff on regulatory issues not specifically covered by the Tariff or issues where there may be conflict or differing interpretations of the Tariff.

6. Respond to special assignments from the MOPC or the SPP BOD.

7. Recommend resources necessary to administer the Tariff for inclusion in SPP’s administrative budget.

8. Work with SPP Staff and other SPP organizational groups to prioritize activities.

9. Review and ensure consistency of language proposed by other Working Groups with the Tariff and FERC policy.
**REPRESENTATION**

RTWG membership will consist of an equal number of representatives from Transmission Owning Members and with an up to equal number of representatives of Transmission Using Members as defined under the SPP Bylaws. Transmission Owning Members shall be included on the RTWG membership roster and not subject to the working group solicitation process.

**DURATION**

Permanent.

**REPORTING**

The RTWG reports to the MOPC. As necessary, the RTWG may appoint a member of the RTWG as a liaison to other working groups for specific issues or action items being coordinated.
## Revision Request Recommendation Report

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<tr>
<td><strong>RR Title:</strong> OCRTF Revisions to Operating Criteria Sections 1, 2, and 3</td>
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### SUBMITTER INFORMATION

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### OBJECTIVE OF REVISION

**Objectives of Revision Request:**

Describe the problem/issue this revision request will resolve.

The Operating Criteria Review Task Force is a joint effort between ORWG and RCWG to perform a wholesale review of SPP Operating Criteria with an emphasis on removing antiquated language and modernizing remaining language. In many cases, the current SPP Operating Criteria contains many redundancies with NERC Reliability Standards. Some portions of SPP Operating Criteria were written approximately two decades ago resulting in a need to modernize the language. This Revision Request represents the culmination of the OCRTF’s efforts in revising SPP Operating Criteria Sections 1, 2, and 3.

Describe the benefits that will be realized from this revision.

By removing antiquated language and modernizing remaining language, the efforts of the OCRTF will result in SPP Operating Criteria that most accurately represents the requirements needed for SPP to perform the Reliability Coordinator, Balancing Authority, Transmission Service Provider, and Reserve Sharing Group functions.

### COMMENTS

The RTWG made non substantive changes to the proposed Operating Criteria language.

Date: 2/22/2018

Action: Motion by Tom Hestermann (Sunflower) seconded by Mo Awad (Westar) to approve RR 268 as modified. The motion passed.

### PROPOSED REVISION

Provide proposed modifications (redlined) to the revision request for which you are providing comments. Use language from the revision request and redline with your additional edits.

### SPP Tariff (OATT)

N/A

### Market Protocols

N/A
1. Glossary

2.1. Introduction

The Operating Criteria contained within this document serves to support the values and principles upon which Southwest Power Pool, Inc. (SPP) is formed. These criteria are reviewed and managed by the Organizational Group structure as described in the SPP Bylaws. Unless stated otherwise in the applicable section of this document, these Operating Criteria shall be reviewed by the Operating Reliability Working Group (ORWG) and any revisions to this document shall be performed pursuant to the approved Revision Request Process and submitted to the Markets and Operations Policy Committee (MOPC) for consideration of approval. The MOPC shall present applicable Revision Requests to the SPP Board of Directors for their review and approval as appropriate.

2.1.1 Purpose

The Operating Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the various SPP Operational and Operating Reliability Functions. Stand-alone governing documents for the purposes of meeting certain NERC Reliability Standards are also referenced in the SPP Operating Criteria.

2.2. Document Relationships

The Operating Criteria developed by SPP provide background information, guidelines, business rules, and processes for the operation and administration of the various SPP Operational and Operating Reliability Functions.

Multiple NERC Reliability Standards require SPP to develop and maintain documents. Such documents can be described by NERC as a ‘methodology’, ‘operating process’, or other descriptions. In such cases where required, SPP shall develop and maintain stand-alone governing documents to meet such NERC Reliability Standard requirements. Each of these stand-alone governing documents will be referenced in the appropriate Operating Criteria section. For the purposes of the SPP Bylaws and the SPP Membership Agreement, these stand-alone governing documents shall be considered an extension of these Operating Criteria.
3.2. Operating Functions Overview

SPP’s Operating Functions include: Reliability Coordinator, Balancing Authority, Transmission Service Provider, and Reserve Sharing Group Administrator. For the purposes of SPP Operating Criteria and Appendices, these functions shall be defined by the NERC Glossary of Terms.

3.12.1 Reliability Coordinator

Southwest Power Pool, Inc. SPP is registered with the North American Electric Reliability Corporation (NERC) as a Reliability Coordinator (RC) for Transmission Operators (TOP’s), Generator Operators (GOP’s) and Balancing Authorities (BA’s). An RC has the highest responsibility and authority to act and direct actions in accordance with relevant NERC Reliability Standards and other directives put forth from the NERC or the Federal Energy Regulatory Commission (FERC) to preserve the integrity of the Bulk Electric System.

3.22.2 Balancing Authority

SPP also functions as Southwest Power Pool, Inc. SPP is registered with NERC as a Balancing Authority for selected TOP’s and GOP’s. A Balancing Authority is a responsibly entity that integrates resource plans ahead of time, maintains load-interchange-generation balancing within the Balancing Authority Area, and supports Interconnection Frequency in real time. SPP’s Integrated Marketplace supports the Balancing Authority function of SPP.

3.32.3 Transmission Service Provider

SPP is also Southwest Power Pool, Inc. SPP is registered with NERC as a Transmission Service Provider for the SPP Open Access Transmission Tariff. SPP administers the provisions of the Tariff and provides Transmission Service to Transmission Customers under the applicable transmission service agreements.

3.42.4 Reserve Sharing Group

Southwest Power Pool, Inc. SPP is registered with NERC as the Reserve Sharing Group (RSG). An RSG is a relationship established by contract between two or more BA’s that collectively maintain, allocate, and supply Operating Reserves required for each member BA’s use in recovering from contingencies within the group. The end result is that a lesser amount of Operating Reserves is maintained among the RSG members than would be required in the absence
of the RSG. NERC Reliability Standards set forth requirements for how the RSG functions and what objectives RSGs must meet to maintain Bulk Electric System reliability.

As the administrator of the SPP RSG, and in coordination with other participating BAs, SPP maintains the *SPP Reserve Sharing Group Operating Process (RSGOP)*. The RSGOP establishes standard terminology and minimum requirements governing the amount and availability of Contingency Reserves, to be maintained by the distribution of Operating Reserve responsibility among members of the RSG. BAs participating in the SPP RSG shall meet the requirements set forth in the *SPP Reserve Sharing Group Operating Process RSGOP*, which can be found on [SPP.org at Documents-Governing](https://www.spp.org) the SPP website.

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<tr>
<th>SPP Planning Criteria</th>
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Revision Request Comment Form

RR #: 269
Date: 2/22/2018

RR Title: OCRTF Revisions to Operating Criteria Sections 4 and 8

SUBMITTER INFORMATION

Name: Marisa Choate on behalf of the RTWG
Company: Southwest Power Pool
Email: mchoate@spp.org
Phone: 501.688.1707

OBJECTIVE OF REVISION

Objectives of Revision Request:
Describe the problem/issue this revision request will resolve.
The Operating Criteria Review Task Force is a joint effort between ORWG and RCWG to perform a wholesale review of SPP Operating Criteria with an emphasis on removing antiquated language and modernizing remaining language. In many cases, the current SPP Operating Criteria contains many redundancies with NERC Reliability Standards. Some portions of SPP Operating Criteria were written approximately two decades ago resulting in a need to modernize the language. This Revision Request represents the culmination of the OCRTF’s efforts in revising SPP Operating Criteria Sections 4 and 8.
Describe the benefits that will be realized from this revision.
By removing antiquated language and modernizing remaining language, the efforts of the OCRTF will result in SPP Operating Criteria that most accurately represents the requirements needed for SPP to perform the Reliability Coordinator, Balancing Authority, Transmission Service Provider, and Reserve Sharing Group functions.

COMMENTS

The RTWG made non substantive changes to the proposed Operating Criteria language.

Date: 2/22/2018
Action: Motion by Tom Hestermann (Sunflower) seconded by Bernie Liu (Xcel) to approve RR 269 as modified. The motion passed.

PROPOSED REVISION

Provide proposed modifications (redlined) to the revision request for which you are providing comments. Use language from the revision request and redline with your additional edits.

SPP Tariff (OATT)

N/A

Market Protocols

N/A

SPP Operating Criteria

3. (Renumbering Sections)

4.3. Reliability Coordination

Continuous coordinated operation of the Bulk Electric System is essential to maintain reliable electric service to all customers. Reliability coordination procedures are established herein for sharing of
operating information and around-the-clock coordination of normal and emergency operating conditions to secure the reliability of the Bulk Electric System.

3.1 SPP Emergency Communication Network

The SPP Emergency Communication Network is comprised of Satellite Phones located at the SPP primary and backup control centers, control centers of each member Balancing Authority and/or Transmission Operator. If loss of any primary communication facilities occurs, the SPP Emergency Communication Network may be used to exchange information. Therefore, it is important for operators to be familiar and comfortable with the operation of the Satellite Phones. The Reliability Coordinator shall ensure proper training upon request.

Balancing Authorities, Transmission Operators and Reliability Coordinators shall participate in weekly testing of the SPP Emergency Communication Network. Testing will ensure reliability and it will also give users practice on the system. The Reliability Coordinator shall initiate and monitor the SPP Satellite Phone testing.

During actual emergency conditions requiring the use of the SPP Emergency Communication Network, the Reliability Coordinator shall initiate a Group Call and quickly determine the extent of the interruption. Communication is vital to an orderly recovery.

Operating personnel shall keep conversations concise to keep channels clear. Priority should be given to establishing voice communication paths prior to re-establishing data communication paths.

4.1 Responsibility and Authority

The Reliability Coordinator has the responsibility and authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise that authority to alleviate capacity and energy emergencies and coordinate restoration activities between individual Transmission Operators. The Reliability Coordinator also shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes, unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.
4.1.1 — Information and Data Exchange

4.1.1.1 — Required Data Specification for the SPP Reliability Coordinator and the SPP Balancing Authority

The SPP Reliability Coordinator and the SPP Balancing Authority shall maintain a documented specification for the data necessary for it to perform its analysis functions, Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The SPP Reliability Coordinator and the SPP Balancing Authority shall distribute its data specification to entities that have data required by the SPP Reliability Coordinator’s and the SPP Balancing Authority’s analysis functions, Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The entities shall satisfy the requirements contained within the “Required Data Specification for the SPP Reliability Coordinator and the SPP Balancing Authority” (RDS). SPP shall be responsible for maintaining the RDS. The Operating Reliability Working Group (ORWG) shall be responsible for initially approving the RDS and reviewing and approving subsequent changes to the RDS. The Reliability Compliance Working Group (RCWG) shall provide formal comments on proposed changes to the RDS prior to ORWG review. SPP shall distribute this document directly to each applicable entity both upon the initial approval and the approval of subsequent changes within 30 days.

4.1.1.2 — SPP Sharing of Externally Provided Data

The SPP Reliability Coordinator shall obtain a current-signed NERC Confidentiality Agreement from entities receiving data provided to SPP by an entity other than SPP ensuring that the confidentiality of the data be maintained as required by the NERC Confidentiality Agreement.

4.1.1.3 — Node Connectivity Requirement (Effective Until 1/1/2018)

SPP operates ICCP nodes at both the primary and disaster recovery (backup) sites. Both the primary and backup site ICCP servers feed real-time data to the primary and backup site Energy Management Systems. To ensure maximum availability of ICCP data required for operating reliability, the following connectivity requirements are required:

- SPP members are required to configure their ICCP servers to connect to the SPP primary and backup sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.
- SPP will normally reference the same ICCP Object ID from both nodes when reading member data, thus imposing no additional maintenance workload upon the member companies.
- Members operating a backup site may choose to concurrently serve data from that site. In that instance, SPP will configure the SPP primary ICCP node to communicate with the member’s primary site node and will configure the SPP backup site ICCP node to communicate with the member backup site node.
- SPP will configure the SPP backup site ICCP nodes to serve data to member sites using a separate and distinct ICCP Object ID in order to permit them to concurrently read operating reliability data from redundant nodes.
4.1.1.43.1.1.1 Node Connectivity Requirement (Effective 1/1/2018)

SPP operates ICCP nodes at both the primary and backup sites. Both the primary and backup site ICCP node feed real-time data to their primary and backup site Energy Management Systems concurrently. To ensure maximum availability of ICCP data required for reliability, the following connectivity requirements are required for entities registered with NERC as a Generator Operator or Transmission Operator within the SPP Reliability Coordinator Area to be binding on January 1, 2018 or as otherwise consistent with waiver provisions outlined in the RDS:

- All Transmission Operators are required to configure their ICCP nodes to connect to the SPP primary and backup sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.
- All Transmission Operators and Generator Operators are required to configure two ICCP nodes so that, in the event of a failure of their active ICCP node, their alternate ICCP node reconnects to SPP’s ICCP nodes within 240 seconds.
  - If the TOP or GOP has a third-party contract for their ICCP connections, then the third party should be able to reconnect within 240 seconds.
- All Generator Operators with more than 1500 MW of net aggregate generation or fifteen capacity resources in the SPP Balancing Authority Area are required to configure two ICCP nodes to read their Integrated Marketplace resource set-point instructions from both SPP’s primary and secondary ICCP nodes concurrently.

In the event of an outage on ICCP Nodes:

- Planned maintenance outages should comply with the Outage Scheduling Information of the RDS (Telemetering and Control System Status). For forced or unplanned outages, the TOP or GOP should contact SPP and follow the Outage Scheduling Information of the RDS (Telemetering and Control System Status).

4.1.1.53.1.1.1 Synchrophasor Data Communication System – Phase I

Synchrophasor technology enables greater visibility into grid conditions by detecting and recording events that SCADA data may miss. SPP’s Synchrophasor System allows SPP to collect, analyze, and archive time-synchronized data from phasor measurement units (PMU) or other phasor measurement recording devices with similar capabilities. SPP is focused on creating a more reliable electric grid by using PMU data to gain a better understanding of the dynamic nature of the grid resulting in increased model accuracy that enables reliable and efficient use of the existing transmission assets.

In Phase I of SPP’s Synchrophasor System project, the PMU devices and the associated data will be used to (a) analyze oscillation modes in the region, (b) analyze and benchmark voltage stability assessments against actual recorded data, (c) record phase angle differences to understand transmission system stress from a wide area overview, (d) perform model validation for operations and planning system stability studies and, (e) provide enhanced insight while researching grid events in post-event analysis. Any change in use may introduce compliance impacts for member companies. The PMU devices and associated data in the SPP Synchrophasor System will not be used for any of the following purposes.
Operational Planning Analysis;

Real-time Assessments; or

Real-time monitoring for purposes of making operational decisions within a 15 minute time horizon.

Prior to implementing subsequent phases of the Synchrophasor System project, this language in this section shall be updated. If SPP relies on the PMU devices for purposes of control and monitoring, it will notify SPP member companies in adherence to CIP-002-5, Attachment 1 Criteria.

4.1.2 Member Responsibilities

Transmission Operators shall determine System Operating Limits (SOLs), as defined by NERC, in conjunction with transmission owners. SOLs will be provided for facilities that comprise flowgates and any other facilities as determined by the Transmission Operator in conjunction with the transmission owners. The Transmission Operator shall inform the Reliability Coordinator of changes to any SOL as specified in Appendix OP 1 and notify the Reliability Coordinator of any SOL exceedances. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with the SOL Methodology in SPP Planning Criteria 7.3.

4.1.2.1 Outage Reporting and Coordination

Each Transmission Operator, Generator Operator and Balancing Authority shall perform the functions specified in OP 2 Outage Coordination Methodology.

4.1.2.1.1 Special Protection Systems

The Transmission Operator shall immediately inform the Reliability Coordinator of the status of any Special Protection System, that may have an inter-Balancing Authority, or inter-Transmission Operator impact, including any degradation or potential failure to operate as expected.

4.1.2.1.2 Other Protection Systems

If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify the Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

4.1.2.1.3 Fuel Supply

Balancing Authorities or Generator Operators, as appropriate, shall notify SPP of any generation derates resulting from Operational Flow Orders (OFOs) or Critical Notices or any other type of fuel delivery constraint. The parties submitting the information shall indicate that the derate is a result of an OFO, Critical Notices, or fuel delivery constraint and indicate which pipeline(s) or delivery constraints are impacting them. Whenever an OFO, Critical Notices, or fuel delivery constraint causes an inability for the Generator Operator to meet its firm obligations, it must use the normal established communication
protocols to notify its host Balancing Authority. Furthermore, Balancing Authorities shall notify the SPP Reliability Coordinator should it be necessary to request a NERC Energy Emergency Alert and/or a SPP Other Extreme Conditions as a result of the OFO or Critical Notice.

4.1.2.2 Vegetation Management

This section of the SPP Criteria is applicable to all entities in the SPP Regional Entity footprint and the SPP Reliability Coordinator footprint. For the purpose of this Criteria and NERC Reliability Standard FAC-003, the SPP Regional Entity [SPP RE], the SPP Reliability Coordinator and the SPP Operating Reliability Working Group are collaborating to act as the Regional Reliability Organization [RRO] as identified in the Standard. NERC Reliability Standard FAC-003 requires a vegetation management program for transmission lines operating at 200kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region. For the purpose of implementing FAC-003-1 and proposed revisions to the FAC-003 standard, the SPP RC will designate the applicable facilities that are to be monitored for compliance to the standard in consultation with the SPP ORWG. The SPP Reliability Coordinator designates the following transmission lines as being subject to the FAC-003 standard:

1. All transmission lines operating at 200kV and above;
2. All transmission lines, not included in 1. above that are listed as monitored or contingent elements of an Interconnection Reliability Operating Limit (IROL) flowgate as published in the SPP IROL Relief Guides.

The SPP Reliability Coordinator develops and identifies IROL flowgates on a continual basis to ensure reliability. However, IROL flowgate facilities will only be added to the applicable lines list annually to provide adequate time for Transmission Owners to incorporate those facilities into their Transmission Vegetation Management Plans. The SPP Reliability Coordinator will maintain the master list of the applicable transmission lines. The facilities identified will become applicable to the standard 12 months after being identified by the SPP RC. The SPP RC is responsible for communicating to the applicable Transmission Owners those transmission lines designated as applicable transmission lines by the SPP RC and subject to compliance monitoring and reporting of vegetation contacts as detailed in NERC Reliability Standard FAC-003. The Transmission Owner shall develop communications and notification protocols for the purposes of implementing changes to the applicable transmission line list and for reporting vegetation contacts to the SPP RE.

4.1.2.3 Transmission Facility Ratings

Each Transmission Owner shall provide the SPP Reliability Coordinator with Normal and Emergency Ratings in accordance with the Transmission Owner’s Facility Rating methodology. Emergency Ratings are helpful in real-time operations, providing system operators a specified time to implement mitigating actions before exceeding pre-contingent or post-contingent System Operating Limits. Transmission Owners shall provide the SPP Reliability Coordinator with the highest available Emergency Rating that provides sufficient time for system operators to take actions that are intended to keep actual loading within applicable limits. The SPP Reliability Coordinator will initiate mitigation procedures with the default assumption that the Emergency Ratings are associated with a finite time period of at least thirty minutes.
For an Emergency Rating associated with a finite time period of less than thirty minutes, an approved operating guide must be on file with the SPP Reliability Coordinator. The operating guide must outline the steps that will be taken to reduce loading on the transmission facility within the finite time associated with the Emergency Rating.

4.1.3 Operating Reliability Working Group

The Operating Reliability Working Group shall be responsible for policy oversight of implementation and ongoing reliability coordination processes and services as described in this Criteria. This working group shall make regular reports to the Markets and Operations Policy Committee.

4.1.4 SPP Staff

The SPP Staff shall be responsible for development and administration of reliability coordination processes and services as described in this Criteria, including budgeting and staffing requirements.

4.1.5 Reliability Coordinator Responsibilities

The SPP Reliability Coordinator shall be responsible for the following activities:

4.1.5.1 Reliability Assessments

(1) Monitor the collection of real-time operating information, schedules and daily forecasts from Balancing Authorities as specified in Appendix OP-1.

(1) Develop and use operational models to ensure that the Bulk Electric System can be operated reliably in anticipated normal and Contingency event conditions. The Reliability Coordinator shall conduct Contingency analysis studies to identify potential interface and other SOL and IROL exceedances, including overloaded transmission lines and transformers, voltage and stability limits, and determining the adequacy of operating reserve for the current operating day and the next day.

(2) Perform Day Ahead Contingency Analysis to assess the impact of any single transmission contingency 100kV and above while monitoring all facilities 100kV and above within the entire SPP RC Footprint and neighboring Balancing Authority Areas or Transmission Operators systems.

(3) Develop mitigation plans or operating guides for any potential interface, SOLs or IROLs found in the Day Ahead Contingency Analysis that is forecast to exceed 100% of the emergency rating of any facility 100kV and above or any pre-contingent bus voltages of +/- 5% and/or post-contingent bus voltages in excess of +/- 10%.

(4) During conditions where system reliability is threatened, notify and coordinate with affected Transmission Operators, Balancing Authorities, or Transmission Service Providers in determining appropriate control action.

(5) Perform voltage stability simulations for identified areas and paths with the potential for post-contingent and real-time voltage stability issues. See Appendix OP-3.

(6) Sharing the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators, Balancing Authorities, and
Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results available no later than 1500 Central Standard Time.

4.1.5.2 Operational Coordination

1. Coordinate and grant permission for bulk transmission equipment maintenance.
2. Coordinate pending generator maintenance.
3. Manage the SPP Open Access Same-Time Information System (OASIS) node and Available Transfer Capability (ATC) calculation.
4. Monitor the NERC Hot line and NERC Reliability Coordinator Information System (RCIS) and disseminating information.
5. Initiating time error corrections (TEC).
6. Initiating Geo-magnetic Disturbance (GMD) notifications and assist as needed in the development of any required response plans.
7. In conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs, and/or mitigate CPS or DCS exceedances.

4.1.5.3 Monitoring

1. Monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
2. Identifying sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
3. Monitor Special Protection Systems that may have an inter-Balancing Authority, or inter- Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL exceedance) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.
4. Monitor applicable transmission line status, real and reactive power flows, voltage, tap-changer settings, and status of rotating and static reactive resources.
5. Coordinate bilateral inadvertent energy accounting and payback.

4.1.5.4 Emergency Procedure Implementation

1. Monitor and coordinate implementation of Operating Reserve Criteria.
Monitor and coordinate implementation of Transmission Loading Relief and other congestion management procedures.

Monitor and coordinate implementation of Load Shedding and Restoration Criteria.

Monitor and coordinate implementation of Black Start Criteria.

Issue short supply advisories.

Issue weather advisories.

Evaluate actions taken to address an IROL or SOL exceedance and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

### 4.1.5.5 Interregional Coordination

(1) Coordinate normal and emergency operations with other Reliability Coordinators.

(1) Authoritatively act on behalf of SPP Members to resolve interregional issues.

### 4.1.5.6 Other Reliability Coordinator Responsibilities

The SPP Reliability Coordinator shall be responsible for the following additional activities:

(1) Coordinate implementation of Black Start procedures as outlined in Criteria.

(1) Implement Transmission Loading Relief Procedures and other congestion management procedures as required.

(2) Administer the SPP Reserve Sharing Group.

(3) Provide reports to the ORWG of congestion management activities performed by the RC. These reports shall also be posted periodically.

### 3.2 Reliability Coordinator Outage Coordination Methodology

The ‘SPP RC Outage Coordination Methodology’ document serves to meet the NERC Reliability Standards requiring an Outage Coordination Methodology for the SPP RC Area. Applicable entities in the SPP RC region shall meet the requirements defined in the ‘SPP RC Outage Coordination Methodology’ document, which can be found on SPP.org at Documents-Governing the SPP website.

### 4.23.3 Reliability Coordinator Performance Standards

The SPP Reliability Coordinator shall have the following performance standards:

(1) The SPP Reliability Coordinator shall act in accordance with Good Utility Practice including NERC Reliability Standards and SPP Criteria, shall not order SPP members to take any action that would not be in accordance with Good Utility Practice or NERC Reliability Standards, and shall allow SPP members to take any actions required by Good Utility Practice and NERC Reliability Standards.
(2) The SPP Reliability Coordinator shall not take any action, or direct SPP members to take any action, which would be in violation of any lawful regulation or requirement of any governmental agency or NERC Reliability Standard.

(3) The SPP Reliability Coordinator shall carry out its responsibilities in at least as prompt and efficient a manner as that required by Good Utility Practice including NERC Reliability Standards and SPP Criteria.

(4) The SPP Reliability Coordinator shall monitor adherence to its directives and report non-compliance to the appropriate SPP organizational group.

(5) The SPP Reliability Coordinator shall possess the applicable NERC Certification.

(6) The SPP Reliability Coordinator shall sign a document to ensure appropriate protection of competitively sensitive information.

4. **Balancing Authority Communications Protocols**

The ‘SPP Reliability Coordinator and Balancing Authority Operating Instruction Communications Protocols’ document exists to improve communications for the issuance of Operating Instructions to reduce the possibility of miscommunication that could lead to action or inaction harmful to the reliability of the Bulk Electric System. Applicable entities are required to follow the ‘SPP Reliability Coordinator and Balancing Authority Operating Instruction Communications Protocols’ document, which can be found on SPP.org at Documents-Governing the SPP website.

5. **Transmission Service Provider Communication of Data**

5.1 **Providing Required Reliability Data to the Reliability Coordinator and Balancing Authority**

The ‘Required Data Specification for the SPP Reliability Coordinator and the SPP Balancing Authority’ document defines data required to perform reliability functions. Applicable entities shall meet the requirements defined in the ‘Required Data Specification for the SPP Reliability Coordinator and the SPP Balancing Authority’ document, which can be found on SPP.org at Documents-Governing the SPP website.

Link to Governing Documents on SPP.org
5.2  **Node Connectivity Requirement (Effective 1/1/2018)**

SPP operates Inter-Control Center Communications Protocol (ICCP) ICCP nodes at both the primary and backup sites. Both the primary and backup site ICCP nodes feed real-time data to their primary and backup site Energy Management Systems concurrently. To ensure maximum availability of ICCP data required for reliability, the following connectivity requirements are required for entities registered with NERC as a Generator Operator or Transmission Operator within the SPP Reliability Coordinator Area to be binding on January 1, 2018 or as otherwise consistent with waiver provisions outlined in the RDS:

- All Transmission Operators are required to configure their ICCP nodes to connect to the SPP primary and backup sites concurrently and to make the same Block 1 and Block 2 data available to both nodes.

- All Transmission Operators and Generator Operators are required to configure two ICCP nodes so that, in the event of a failure of their active ICCP node, their alternate ICCP node reconnects to SPP’s ICCP nodes within 240 seconds.
  - If the TOP or GOP has a third party contract for their ICCP connections, then the third party should be able to reconnect within 240 seconds.

- All Generator Operators with more than 1500 MW of net aggregate generation or fifteen capacity resources in the SPP Balancing Authority Area are required to configure two ICCP nodes to read their Integrated Marketplace resource set point instructions from both SPP’s primary and secondary ICCP nodes concurrently.

In the event of an outage on ICCP Nodes:

- Planned maintenance outages should comply with the Outage Scheduling Information of the RDS (Telemetering and Control System Status). For forced or unplanned outages, the TOP or GOP should contact SPP and follow the Outage Scheduling Information of the RDS (Telemetering and Control System Status).

5.3  **Synchrophasor Data Communication System – Phase I**

Synchrophasor technology enables greater visibility into grid conditions by detecting and recording events that SCADA data may miss. SPP’s Synchrophasor System allows SPP to collect, analyze, and archive time-synchronized data from phasor measurement units (PMU) or other phasor measurement recording devices with similar capabilities. SPP is focused on creating a more reliable electric grid by using PMU data to gain a better understanding of the dynamic nature of the grid resulting in increased model accuracy that enables reliable and efficient use of the existing transmission assets.

In Phase I of SPP’s Synchrophasor System project, the PMU devices and the associated data will be used to (a) analyze oscillation modes in the region, (b) analyze and benchmark voltage stability assessments against actual recorded data, (c) record phase angle differences to understand transmission system stress from a wide-area overview, (d) perform model validation for operations and planning system stability studies and, (e) provide enhanced insight while researching grid events in post-event analysis. Any change
in use may introduce compliance impacts for member companies. The PMU devices and associated data in the SPP Synchrophasor System will not be used for any of the following purposes:

- Operational Planning Analysis;
- Real-time Assessments; or
- Real-time monitoring for purposes of making operational decisions within a 15 minute time horizon.

Prior to implementing subsequent phases of the Synchrophasor System project, this language in this section shall be updated. If SPP relies on the PMU devices for purposes of control and monitoring, it will notify SPP member companies in adherence to CIP-002-5, Attachment 1 Criteria.

### 8. Emergency Communication

Dependable communications are critical to maintaining the reliability of the Bulk Electric System. Accordingly, NERC has outlined necessary communication links in the reliability standards applying to Transmission Operators, Balancing Authorities, and Reliability Coordinators. It is vital that communication channels are functional and disturbances to the communication network should be addressed.

**Key critical paths:**

1. Internal communications
2. Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.
3. With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.
4. Where applicable, these facilities shall be redundant and diversely routed.

The communication paths should be verified periodically and an action plan should exist to maintain and recommend solutions to communication problems.

#### 8.1 SPP Emergency Communication Network

The SPP Emergency Communication Network is comprised of Satellite Phones located at the SPP primary and backup control centers, control centers of each member Balancing Authority and/or Transmission Operator. If loss of any primary communication facilities are encountered, the SPP Emergency Communication Network shall be used to exchange information. Therefore, it is important for operators to be familiar and comfortable with the operation of the Satellite Phones. The Reliability Coordinator shall ensure proper training.
Balancing Authorities, Transmission Operators and Reliability Coordinators shall participate in weekly testing of the SPP Emergency Communication Network. Testing will ensure reliability and it will also give users practice on the system. The Reliability Coordinator shall initiate and monitor the SPP Satellite Phone testing.

During actual emergency conditions requiring the use of the SPP Emergency Communication Network, the Reliability Coordinator shall initiate a Group Call and quickly determine the extent of the interruption. Communication is vital to an orderly recovery. Operating personnel shall keep conversations concise to keep channels clear. Priority should be given to establishing voice communication paths prior to re-establishing data communication paths.

8.2 --- Information Priority during Emergencies

System status conditions to be surveyed include but are not limited to the following items:

1. Areas of the electric system which are de-energized,
2. Areas of the electric system which are functioning,
3. Amount of generation and generating reserve available in functioning areas,
4. Power plant availability and time required to restart,
5. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants,
6. Status of transmission breakers and sectionalizing equipment at tie points to other areas,
7. Status of fuel supply from external suppliers,
8. Under-frequency relay operation,
9. Relay flags associated with circuits tripped by protective relays,
10. Status of communication systems.

* Refer to COM-001 and COM-002 for more information on maintaining reliable communications

<table>
<thead>
<tr>
<th>SPP Planning Criteria</th>
<th>N/A</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPP Business Practices</td>
<td>N/A</td>
</tr>
<tr>
<td>Integrated Planning Model (ITP Manual)</td>
<td>N/A</td>
</tr>
<tr>
<td>Revision Request Process</td>
<td>N/A</td>
</tr>
<tr>
<td>Minimum Transmission Design Standards for Competitive Upgrades (MTDS)</td>
<td>N/A</td>
</tr>
<tr>
<td>-------------------------------------------------------------</td>
<td>-----</td>
</tr>
<tr>
<td>Reliability Coordinator and Balancing Authority Data Specifications (RDS)</td>
<td>N/A</td>
</tr>
<tr>
<td>SPP Communications Protocols</td>
<td>N/A</td>
</tr>
</tbody>
</table>
Revision Request Comment Form

RR #: 270 | Date: 2/22/2018

**RR Title:** OCRTF Revisions to Operating Criteria Appendices

**SUBMITTER INFORMATION**

| Name: | Marisa Choate on behalf of the RTWG |
| Company: | Southwest Power Pool |
| Email: | mchoate@spp.org |
| Phone: | 501.688.1707 |

**OBJECTIVE OF REVISION**

**Objectives of Revision Request:**

Describe the problem/issue this revision request will resolve.

The Operating Criteria Review Task Force is a joint effort between ORWG and RCWG to perform a wholesale review of SPP Operating Criteria with an emphasis on removing antiquated language and modernizing remaining language. In many cases, the current SPP Operating Criteria contains many redundancies with NERC Reliability Standards. Some portions of SPP Operating Criteria were written approximately two decades ago resulting in a need to modernize the language.

This Revision Request represents the culmination of the OCRTF’s efforts in revising SPP Operating Criteria Appendices. This Revision Request also proposes the creation of the stand-alone ‘SPP Reliability Coordinator Outage Coordination Methodology’ using the current content of Appendix OP-2 as the basis.

Describe the benefits that will be realized from this revision.

By removing antiquated language and modernizing remaining language, the efforts of the OCRTF will result in SPP Operating Criteria that most accurately represents the requirements needed for SPP to perform the Reliability Coordinator, Balancing Authority, Transmission Service Provider, and Reserve Sharing Group.

The creation of the stand-alone ‘SPP Reliability Coordinator Outage Coordination Methodology’ will further ensure consistency in using stand-alone documents where necessary to meet certain requirements in NERC Reliability Standards.

**COMMENTS**

The RTWG made non substantive changes (Southwest Power Pool, Inc. vs. SPP and calendar days vs. days) to the proposed language.

Date: 2/22/2018

Action: Motion by Jessica Meyer (LES) seconded by Jim Bixby (ITC) to approve RR 270 as modified. The motion passed.

**PROPOSED REVISION**

Provide proposed modifications (redlined) to the revision request for which you are providing comments. Use language from the revision request and redline with your additional edits.

**SPP Tariff (OATT)**

N/A

**Market Protocols**

N/A
<table>
<thead>
<tr>
<th>Section</th>
<th>N/A</th>
</tr>
</thead>
<tbody>
<tr>
<td>SPP Operating Criteria</td>
<td></td>
</tr>
<tr>
<td>SPP Planning Criteria</td>
<td></td>
</tr>
<tr>
<td>SPP Business Practices</td>
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</tr>
<tr>
<td>Integrated Planning Model (ITP Manual)</td>
<td></td>
</tr>
<tr>
<td>Revision Request Process</td>
<td></td>
</tr>
<tr>
<td>Minimum Transmission Design Standards for Competitive Upgrades (MTDS)</td>
<td></td>
</tr>
<tr>
<td>Reliability Coordinator and Balancing Authority Data Specifications (RDS)</td>
<td></td>
</tr>
<tr>
<td>SPP Communications Protocols</td>
<td></td>
</tr>
</tbody>
</table>
Appendix OP-2: Southwest Power Pool

Reliability Coordinator - Outage Coordination Methodology

Purpose

The purpose of this methodology is to provide technical requirements and criteria to Transmission Operators, Generator Operators and SPP Staff related to submission of Transmission and Generation outages to the Southwest Power Pool, Inc. (SPP) Reliability Coordinator and SPP Balancing Authority via the SPP CROW tool. Outage submissions will be shared with other Reliability Coordinators, Transmission Operators, and Balancing Authorities via the NERC System Data Exchange (SDX) and will be used for assessing real-time and future reliability of the Bulk Electric System. Transmission and Generator Operators are responsible for submitting all outages through the CROW tool. All other Transmission Operators will be able to view and identify all outages that are submitted through the CROW tool. SPP reserves the right to approve, deny, or reschedule any outage deemed necessary to ensure system reliability on a case by case basis regardless of date of submission.

Use of Capitalized Terms

For the purposes of this document, the following rules should be used concerning the use of capitalized terms. Non-italicized capitalized terms are defined by the NERC Glossary of Terms. Italicized capitalized terms indicate terms used in the CROW tool itself. Further description of many of these italicized capitalized terms can be found in the CROW Outage Scheduler Web GUI Tutorial.
1. Transmission Outages and Operations

For the purpose of identifying applicable facilities, the nominal kV level of the facility will be used. For transformers, use the low side voltage class. Example: A 161/69kV transformer shall be classified as a 69kV facility for the purposes of this methodology.

a. Forced Transmission Outage Submission Requirements

Forced outages of all transmission facilities greater than 60kV that are modeled in the SPP regional models and have been modeled in the CROW tool should be submitted within 30 minutes or as soon as practical after the outage. Each outage submission must be accompanied by a Planned End Time, Forced Outage Priority, an associated Outage Request Type, and an Outage Cause. Forced Outage Priority outages will be considered Non-Recallable. At the time of submission, forced outage reasons may not be known so a reason of Unknown may be selected. It is recognized that the duration of a forced outage will typically not be known at the time of the initial submission. The Planned End Time should be the best estimate for the return of the outaged facility. Any known updates to the Planned End Time and/or reason for the outage shall be submitted promptly to the CROW tool.

b. Scheduled Transmission Outage Submission Requirements

Scheduled outages of all BES elements must be submitted to the CROW tool and approved by the Reliability Coordinator prior to implementing the outage. Scheduled outages of all other transmission elements greater than 60kV that are modeled in the SPP regional models must be submitted to the Reliability Coordinator’s CROW tool for coordination and review. Each outage submission must be accompanied by a Planned Outage Start Time and Planned End Time, Outage Priority, Outage Request Type, and Outage Cause. Each outage request must also be designated as Non-Recallable, or
provide an expected \textit{Recall Time} if directed. Sufficient notation in the outage scheduler \textit{“Requestor Notes”} comment field should include a description or explanation for the outage. An incomplete outage request of any missing data could result in the outage being denied. Once the actual outage takes place, the \textit{Actual Start Time} of the outage must be submitted to the CROW tool. When the outage has ended, the \textit{Actual End Time} of the outage must be updated.

c. Transmission Outage Priority and Timing Requirements

Each \textit{Transmission Outage} submitted must include one of the following \textit{Outage Priorities}. \textit{Forced Outages} of equipment must be submitted with an \textit{Outage Priority} of \textit{Forced} as defined below. The CROW \textit{Outage Scheduler tool} will enforce the lead time requirements of each \textit{Outage Priority}. Outages that are not planned will have a lower priority and may not be approved by the RC. Outages not submitted as planned will be reviewed and approved by SPP on a case-by-case basis. The risk of imminent equipment failure will have priority over other outages including planned. If sufficient time is not available to analyze the request then the outage will be denied.

<table>
<thead>
<tr>
<th>Priority</th>
<th>Definition</th>
<th>Minimum Lead Time</th>
<th>Maximum Lead Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned</td>
<td>Equipment is known to be operable with little risk of leading to a forced outage. As required for preventive maintenance, troubleshooting, repairs that are not viewed as urgent, system improvements such as capacity upgrades, the installation of additional facilities, or the replacement of equipment due to obsolescence.</td>
<td>14 Calendar Days</td>
<td>None</td>
</tr>
<tr>
<td>Discretionary</td>
<td>Equipment is known to be operable with little risk of leading to a forced outage; however the timeline for submission of Planned outage priority has passed. Discretionary outages are required to be submitted at least 12 calendar days in advance. Due to the shorter lead time, this outage priority has increased risk of being denied based upon higher priority outage requests.</td>
<td>12 Days</td>
<td>14 Calendar Days</td>
</tr>
<tr>
<td>Opportunity</td>
<td>Lead time may be very short or zero. An outage that can be taken due to changed system conditions (ie Generator suddenly offline for forced outage allows transmission work to be done).</td>
<td>None</td>
<td>7 Days</td>
</tr>
</tbody>
</table>
Operational: Equipment is removed from service for operational reasons such as voltage control, constraint mitigation as identified in an operating procedure, etc.

Urgent: Equipment is known to be operable, yet carries an increased risk of a forced outage or equipment loss. The equipment remains in service until maintenance crews are ready to perform the work.

Emergency: Equipment is to be removed from service by operator as soon as possible because of safety concerns or increased risk to grid security.

Forced: Equipment is out of service at the time of the request.

---

d. Transmission Outage Equipment Request Types

Each Transmission outage (scheduled and forced) request submitted must include one of the following Outage Request Types.

<table>
<thead>
<tr>
<th>Outage Request Type</th>
<th>Definition</th>
<th>Modeling Assumptions</th>
</tr>
</thead>
<tbody>
<tr>
<td>Out of Service (OOS)</td>
<td>Equipment is out of service.</td>
<td>SDX = Open&lt;br&gt;EMS = Open</td>
</tr>
<tr>
<td>Normally Open (NO)</td>
<td>Equipment is normally out of service and is identified as normally open in the SPP regional models. Normally Open request type is used to close (place in service) a normally open facility.</td>
<td>SDX = Closed&lt;br&gt;EMS = Closed</td>
</tr>
<tr>
<td>Informational (INF)</td>
<td>Used for outage events that are not covered by one of the other Outage Equipment Request Types. Not an out of service event.</td>
<td>None – Informational Only</td>
</tr>
<tr>
<td>Hot Line Work (HLW)</td>
<td>Work is being performed on live or energized equipment.</td>
<td>None – Informational Only</td>
</tr>
<tr>
<td>General System Protection (GSP)</td>
<td>Work is being performed on protection systems. Requestor shall specifically identify protection systems out of service and any modification to operation or behavior of system contingencies.</td>
<td>None – Informational Only</td>
</tr>
</tbody>
</table>

---

e. Transmission Outage Request Reasons/Causes

Each Transmission Outage Request must be submitted with one of the following reasons for the outage.

<table>
<thead>
<tr>
<th>Reason/Cause</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Category</td>
<td>Description</td>
</tr>
<tr>
<td>----------------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Maintenance &amp; Construction</td>
<td>Outages to facilitate repair, maintain, or upgrade of facility related equipment. This includes clearances to perform vegetation management. Does not include outages to support Maintenance &amp; Construction of other facilities. Those should be submitted as Voltage or SOL Mitigation.</td>
</tr>
<tr>
<td>Third Party Request</td>
<td>Non-transmission facility related requests for clearance or work such as highway construction.</td>
</tr>
<tr>
<td>Voltage Mitigation</td>
<td>Operation of facilities to preserve or correct Bulk Electric System voltage.</td>
</tr>
<tr>
<td>SOL Mitigation (Thermal)</td>
<td>Operation of facilities to preserve or correct Bulk Electric System thermal loading issues.</td>
</tr>
<tr>
<td>Weather/Environmental/Fire (excluding Lightning)</td>
<td>Outages caused by wind, ice, snow, fire, flood, etc. All weather or environmental causes excluding lightning strikes.</td>
</tr>
<tr>
<td>Lightning</td>
<td>Outages caused by direct or indirect Lightning strikes.</td>
</tr>
<tr>
<td>Foreign Interference (including contamination)</td>
<td>Outages caused by blown debris, bird droppings, kites, falling conductors, airplanes, etc.</td>
</tr>
<tr>
<td>Vandalism/Terrorism/Malicious Acts</td>
<td>Outages resulting from known or suspected vandalism, terrorism, or other malicious acts.</td>
</tr>
<tr>
<td>Equipment Failure</td>
<td>Outages resulting from failure of facility related equipment.</td>
</tr>
<tr>
<td>Imminent Equipment Failure</td>
<td>Operation of facilities due to expected imminent facility rated equipment failure.</td>
</tr>
<tr>
<td>Protection System Failure including Undesired Operations</td>
<td>Operation of facilities due to failure or undesired operation of the facility protection systems.</td>
</tr>
<tr>
<td>Vegetation</td>
<td>Outages resulting from contact with vegetation. This does not include outages due to clearances required to perform vegetation management which should be submitted as Maintenance &amp; Construction. This does not include vegetation blown into rights of way or into contact with facilities which should be submitted as Foreign Interference.</td>
</tr>
<tr>
<td>BES Condition (Stability, Loading)</td>
<td>Outages resulting from Bulk Electric System conditions such as islanding, cascading outages, sudden thermal loading due to other contingencies, transient stability conditions, etc.</td>
</tr>
<tr>
<td>Unknown</td>
<td>Operation of facilities due to an unknown reason. Most forced outages will be submitted with an initial reason of Unknown. Once the actual reason for the operation is known, the outage requestor should update the outage request. SPP Staff will follow up after some time to determine the actual outage reason for any outages which still have a reason of Unknown submitted.</td>
</tr>
<tr>
<td>Upcoming Model Change</td>
<td>Outages created for the purpose of correcting system topology related to pending model changes. This cause should only be used by SPP operations personnel.</td>
</tr>
<tr>
<td>Other</td>
<td>Operation of facilities due to a reason not listed here.</td>
</tr>
</tbody>
</table>

2. Generation Outages/Derates

   a. Generation Outages/Derate Submission Requirements
All generating resources within the SPP Reliability Coordinator Area or Balancing Authority Area meeting one or more of the criteria listed below (regardless of voltage connection) shall report in the CROW tool all Outages and Derates if the gross reduction in capability is greater than or equal to 25 MW. Changes to the reported capability shall be reported in 25 MW increments from the last reported Derate level regardless of system capability/conditions.

1. Generating resource(s) with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 25 MVA; or
2. Blackstart Resources identified in a Transmission Operator’s restoration plan; or
3. Dispersed power producing resources with aggregate capacity greater than 25 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity.

If SPP requires generating resources that do not meet the criteria above to report their Outages and/or Derates in the CROW tool, then SPP shall send a written notice to the responsible entity stating their obligations and identifying the specific generating resources.

For the generating resources under the functional control of a Generator Operator (GOP) registered with NERC, the GOP shall be the responsible entity for reporting Outages and Derates in the CROW tool. For all other generating resources not under the functional control of a registered GOP, the resource owner shall be the responsible entity for reporting Outages and Derates in the CROW tool.

b. Forced Generation Outages/Derate Submission Requirements

Forced outages or capability limitations in the form of Derates should be submitted within 30 minutes or as soon as practical after the outage or capability limitation occurs. Forced Generation Outages and Derates are required to be accompanied by a reason for the outage or limitation. Each Outage or Derate submission must be
accompanied by a *Planned End Time*, a *Forced Outage Priority*, *Outage Request Type*, and an *Outage Cause*. *Forced Outage Priority* requests will be assumed to be *Non-Recallable*. At the time of submission, forced outage reasons may not be known so a reason of Unknown may be selected. The *Planned Start Time* of the outage should reflect the best known time of the actual outage. The CROW tool will ensure that the *Actual Start Time* and *Planned Start Time* are equal. Any known updates to the *Planned End Time* and/or reason for the outage shall be submitted promptly to the CROW tool. This outage submission shall be in addition to any other notifications made to SPP such as through a *Reserve Sharing* event, or a *Resource Plan* submission. SPP shall accept each forced outage within 30 minutes of submission.

c. **Scheduled Generation Outages/Derate Submission Requirements**

*Scheduled Outages* or capability limitations in the form of *Derates* should be submitted as soon as possible and to the extent possible on an annual rolling basis. *Planned Generation Outages* are required to be accompanied by a reason for the outage or limitation. Each *Outage* or *Derate* submission must be accompanied by a *Planned Outage Start Time* and *Planned End Time*, an associated *Outage Priority*, an associated *Outage Request Type*, and an *Outage Cause*. Each outage request must also be designated as *Non-Recallable*, or provide an expected *Recall Time* if directed. Once the actual outage takes place, the *Actual Start Time* of the outage must be submitted to the CROW tool. SPP shall respond to all scheduled outages or capacity limitation changes in the CROW *system-tool* within 30 minutes from the time of submission for changes that are effective within the next 48 hours. When the outage has ended, the *Actual End Time* of the outage must be updated. This outage submission shall be in addition to any other notifications made to SPP such as through a *Reserve Sharing* event or a *Resource Plan* submission.

1. **Reserve Shutdown**
(1) Resources in SPP are considered to be in a *Reserve Shutdown* outage status when SPP has approved an outage request via the CROW tool, making the resource unavailable for SPP commitment and dispatch due to reasons other than to perform maintenance or to repair equipment. These resources will be reflected in *Planned Outage* for a reason of *Excess Capacity/Economic*.

(2) Resources that are offline for economic or excess capacity reasons and can be recalled, started, and synchronized to pick up load within 7 days are not required to request an outage via the CROW tool. However, these resources may request and be shown in *Reserve Shutdown* outage status if the outage is approved by SPP.

d. *Generation Outage/Derate Priority and Timing Requirements*

Each *Generation Outage* or *Derate* submitted must include one of the following *Outage Priorities*. Forced outages of equipment must be submitted with a *Priority* of *Forced* as defined below. The CROW tool will enforce the lead time requirements of each *Outage Priority*.

<table>
<thead>
<tr>
<th>Priority</th>
<th>Definition</th>
<th>Minimum Lead Time</th>
<th>Maximum Lead Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planned</td>
<td>Equipment is known to be operable with little risk of leading to a forced outage. As required for preventive maintenance, troubleshooting, repairs that are not viewed as urgent, system improvements such as capacity upgrades, the installation of additional facilities, or the replacement of equipment due to obsolescence.</td>
<td>14 Calendar Days</td>
<td>None</td>
</tr>
<tr>
<td>Opportunity</td>
<td>Lead time may be very short or zero. An outage that can be taken due to changed system conditions (ie Loading conditions allow planned work to occur with short lead time).</td>
<td>None</td>
<td>14 Calendar Days</td>
</tr>
<tr>
<td>Operational</td>
<td>Equipment is removed from service for operational reasons. This could include outages or derates due to reliability directives or other operational concerns not necessarily related to the generating equipment or capability, and outages entered to correct system topology in operating models.</td>
<td>None</td>
<td>None</td>
</tr>
</tbody>
</table>
Urgent

Equipment is known to be operable, yet carries an increased risk of a forced outage or equipment loss. The equipment remains in service until maintenance crews are ready to perform the work.

Emergency

Equipment is to be removed from service by operator as soon as possible because of safety concerns or increased risk to grid security.

Forced

Equipment is out of service at the time of the request.

24 Hours

48 Hours

None

24 Hours

None

1 Hour

---

e. Generation Outage/Derate Request Type

Each *Generation Outage* or *Derate* request submitted must include one of the following *Outage Request Types*.

<table>
<thead>
<tr>
<th>Request Type</th>
<th>Definition</th>
<th>Modeling Assumption</th>
</tr>
</thead>
</table>
| Out of Service | Generator or Resource is out of service. | SDX = offline  
EMS = offline |
| Derate | Generator or Resource maximum capability is lowered from normal operation. A new maximum capability is required to be submitted with each Outage Request Type of Derate. | SDX = online, with new lower PMAX  
EMS = online, with new lower PMAX |
| Informational (INF) | Used for communicating and documenting information to SPP regarding the resource. This status is not interpreted as a loss of capability or capacity. This status may be used to communicate anticipated fuel delivery issues. | None – Informational Only |

f. Generation Outage/Derate Request Reasons/Causes

Each *Generation Outage* or *Derate Request* must be submitted with one of the following reasons for the outage.

<table>
<thead>
<tr>
<th>Reason/Cause</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Equipment Failure</td>
<td>Failure in station generation, prime mover, or other equipment has occurred. Does not include failure of GSU transformers or interconnection facilities. Does include equipment related to fuel delivery considered a part of the resource (such as a coal mill).</td>
</tr>
<tr>
<td>Imminent Equipment Failure</td>
<td>Expected failure in station generation, prime mover, or other equipment. Does not include failure of GSU transformers or interconnection facilities. Does include equipment related to fuel delivery considered a part of the resource (such as a coal mill).</td>
</tr>
</tbody>
</table>
### BES Reliability
Removal from service or limitation to preserve or correct Bulk Electric System reliability issues either through action of a Special Protection System, runback scheme, or as mitigation of another reliability event.

### Loss of Interconnection
Failure in interconnection equipment such as GSU transformers or other interconnection facilities. Does not include loss of synchronization due to stability or islanding type events.

### BES Stability
Removal from service or limitation due to Bulk Electric System stability issues. Includes loss of synchronization due to transient stability and/or islanding issues.

### Fuel Supply
Removal from service or limitation due to fuel supply interruption. Does not include local equipment failures related to fuel supply. Includes loss of gas pressure due to offsite issue, coal supply exhaustion, lack of headwater issues for hydro, etc.

### Regulatory/Safety/Environmental
Removal from service or limitation due to Regulatory/Safety/Environmental restrictions such as emission limits, OSHA, NRC, or other regulatory body limitations. Includes damage caused by weather including but not limited to lightning, flood, earthquake, etc. This may also include limitations to hydro due to low dissolved oxygen in tailwater or to control downstream flooding.

### Unknown
The default Forced Outage/Derate reason will be pre-populated with Unknown at the time of submittal. Either during the initial outage submittal or at a later time, the Unknown reason must be changed to reflect the actual experienced issue.

### Routine Generator Maintenance
Removal from service or limitation in order to perform repair or inspection of generation equipment.

### Supporting Transmission Outage
Removal from service or limitation in order to support a scheduled transmission outage.

### Excess Capacity/Economic
Removal from service or limitation due to seasonal or system capacity need. This includes peaker units not expected to be used during winter months.

### Upcoming Model Change
Outages created for the purpose of correcting system topology related to pending model changes. This cause should only be used by SPP operations personnel.

### Outage Review / Approval Process
All outages submitted will be studied to determine if any potential reliability conflicts are found. The general study method employed by SPP staff involves building representative models of the study time period and implementing all outage requests submitted for that time period. The resulting modeled system is then studied to determine if any reliability issues can be identified. If issues are identified, various mitigation steps are then studied.
including but not limited to, generation redispatch, system reconfiguration, rescheduling of lower priority outages, and facility rating reviews. If mitigations are unsuccessful in resolving the conflict, an outage request may need to be rescheduled or denied. Priority of outage requests is reviewed based upon initial submission time, outage priority category, reason for the outage, and impact to reliability. To the extent possible, higher priority category requests will be given preference, but ultimately it is up to the SPP RC to resolve any scheduling conflicts.

In the event that a conflict occurs with another Reliability Coordinator’s outage, a priority of the outages will be determined based on submitted time, reason for outage, and impact to reliability. The determination will be reviewed and agreed upon by each Reliability Coordinator. The outage that is deemed a higher priority will be approved.

An outage that has been studied will receive a status change to one of the following statuses: Approved, Denied, or Pre-Approved. Pre-Approval will be provided in certain cases where an outage has been submitted, but for various reasons SPP is unable to adequately study the outage or determine that no reliability conflicts exist. The Pre-Approval may also be dependent upon a specific operating condition that may need to be met but cannot be guaranteed at the time the Pre-Approval is issued such as but not limited to a load forecast threshold, simultaneous outage, new facilities in-service, etc. When the outage request can be adequately studied to determine that no reliability conflict exists, the status will be changed to Approved.

All outages submitted within the appropriate advance timeframe will be reviewed as soon as possible by SPP Operations Staff. The review timelines for SPP are as follows:

a. Transmission

   1. For all BES outage requests submitted 30 days or more prior to scheduled start time, Pre-Approval or Denial will be provided within 5 business days.
2. For all BES outage requests submitted 14 days or more but less than 30 days prior to the scheduled start time, Pre-Aapproval or Denial will be provided within 3 business days.

3. For all BES outage requests submitted 14 days or less prior to scheduled start time, Pre-Aapproval or Denial will be provided within 2 business days.

b. Generators

1. For all Generator Outage Requests submitted 30 days or more prior to scheduled start time, Pre-Aapproval or Denial will be provided within 5 business days.

2. For all Generator Outage Requests submitted 14 days or more but less than 30 days prior to the scheduled start time, Approval, Pre-Aapproval or Denial will be provided within 3 business days.

3. For all Generator outage requests submitted 14 days or less prior to scheduled start time, Approval, Pre-Aapproval or Denial will be provided within 2 business days.

4. SPP will provide their best effort for Outages Submitted within 2 business days.

4. Outage Status Changes

All outages submitted will reside in one of several status types throughout the life cycle of the outage. These status types and their associated definition are:

<table>
<thead>
<tr>
<th>Status</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed</td>
<td>The outage request has been saved in the CROW tool and remains under the full revision control until the outage is entered into a Submitted state by the requestor. If the requestor does not move a proposed request to the submitted status within 30 days of the planned start date, the outage is automatically Withdrawn. Proposed outage request status dates DO NOT qualify for outage queuing in conflict resolution. Proposed outage requests are not provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Submitted</td>
<td>The outage request has been submitted into the CROW tool and is ready for review by SPP. The outage requestor does not possess revision control of the outage in this status. A revision request may be submitted to SPP.</td>
</tr>
</tbody>
</table>
regarding an outage in Submitted status. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.

**Study**

SPP will change the status type to Study once the active study process begins. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.

**Preliminary Approved**

Outage requests with Preliminary Approved status have been approved based on long lead studies and may need additional analysis closer to the planned start date or finalization of an Operating Guide. Once the restudy is complete or final opguide posted, the outage status is changed to Approved. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.

**Approved**

Approved state indicates SPP has completed the study process and the outage request is ready for implementation. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.

**Implemented**

Once the outage request actual start time has been entered, signifying that the outage has begun, the outage status is changed to Implemented. Outage requests in this state are provided to external systems such as NERC SDX/IDC or SPP’s EMS.

**Completed**

Once the outage request actual end time has been entered, signifying that the outage has ended, the outage status is changed to Completed. Outage requests in this state are NO LONGER provided to external systems such as NERC SDX/IDC or SPP’s EMS.

Certain outage requests may result in a need by the outage requestor to withdraw or cancel the outage request. SPP’s study results and coordination may also result in status changes to an outage reflecting the inability of the Outage Request to be Approved or Implemented. These status types are:

<table>
<thead>
<tr>
<th>Status</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Withdrawn</td>
<td>The outage requestor can withdraw an outage request while it is still in Proposed status. Once in Study or Approved status, the request must be Cancelled. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Cancelled</td>
<td>The outage requestor can cancel a Submitted or Approved outage. Cancelled outages can be reinstated by the requestor, provided the planned start of the outage falls within the business rules for lead time submission. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
<tr>
<td>Denied</td>
<td>An outage request that is in Submitted or Study status can be Denied. If SPP denies the request, the status changes to Denied. This state indicates the outage request was not approved for implementation. Outage requests in this state are NOT provided to external systems such as NERC SDX/IDC or SPP’s EMS.</td>
</tr>
</tbody>
</table>
5. Using CROW to Submit Other Types of Information to SPP

The **CROW tool** can be used as a mechanism to submit information to SPP other than outage and or status information on lines, transformers, and generators. All other types of information exchange made using the CROW tool not previously described in this Appendix 12 OP-2 SPP RC Outage Coordination Methodology will follow the guidelines below.

For *Reactor, Capacitor, Circuit Breaker, Disconnect, and Protection Scheme* (Special Protection System) **Equipment Types**,

1. All CROW tool submissions for these equipment types will be made in accordance with SPP RC Outage Coordination Methodology Appendix 12 OP-2 Sections 1d, 1e, and 1f
2. **SPP RC Outage Coordination Methodology Appendix 12 OP-2 Section 3 Outage Review / Approval Process** will not apply to these equipment types
3. These equipment types will not progress through the various states described in SPP RC Outage Coordination Methodology Appendix 12 OP-2 Section 4 Outage Status Changes

For *Generator Automatic Voltage Regulator (AVR) and Power System Stabilizers Equipment Types*,

1. All CROW tool submissions for this equipment type will be made in accordance with SPP RC Outage Coordination Methodology Appendix 12 OP-2 Sections 2c, 2d, and 2e
2. **SPP RC Outage Coordination Methodology Appendix 12 OP-2 Section 3 Outage Review / Approval Process** will not apply to these equipment types
3. These equipment types will not progress through the various statuses described in SPP RC Outage Coordination Methodology Appendix 12 OP-2 Section 4 Outage Status Changes
Revision Request Comment Form

RR #: 259
Date: 2/22/2018

RR Title: Settlement Statements Timelines

SUBMITTER INFORMATION

Name: Marisa Choate on behalf of the RTWG
Company: Southwest Power Pool
Email: mchoate@spp.org
Phone: 501.688.1707

OBJECTIVE OF REVISION

Objectives of Revision Request:
Describe the problem/issue this revision request will resolve.

This Revision Request provides changes to the market settlement posting and dispute timelines to be implemented with the new settlement system. The goal of these modifications is to reduce the amount of manual processes as a result of meter and Bilateral Settlement Schedules (BSS) revisions, as well as reduce the number of Resettlement postings.

While the expectation is that the timing of the initial settlement does not change, there could be multiple options around the 2nd and 3rd Scheduled Settlement Statement postings and associated timelines – as long as the guidelines provided in the list that follows are adhered to so that the associated benefits can be attained.

New Settlements/Dispute Timeline:

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<table>
<thead>
<tr>
<th>4</th>
<th>7</th>
<th>48</th>
<th>53</th>
<th>90</th>
<th>110</th>
<th>120</th>
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</thead>
<tbody>
<tr>
<td>S7</td>
<td>S53</td>
<td>S120</td>
<td>Ad hoc out to 330</td>
<td></td>
<td></td>
<td></td>
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</tbody>
</table>
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Describe the benefits that will be realized from this revision.

1. Remove current requirement to submit settlement disputes for meter / BSS data revisions after the final Settlement (OD+47) by adding an additional window for member data submissions
   **Benefit:** Manual processes required to manage the large volume of resettlements resulting from meter revisions has become extremely cumbersome for both the MPs and SPP to manage
   - MP must log a meter dispute in RMS and communicate with the MA regarding needed revisions, as well as confirm with SPP that the correct files have been provided by the MA
   - SPP must manually load the meter revisions (since only meter values disputed can be included in resettlement), update the settlement calendar, and track each individual meter dispute to ensure it is pulled into a resettlement

2. Add a 3rd opportunity for revised meter and BSS data to get included in a settlement run by adding a 3rd Scheduled Settlement (S7, S53, S120)
   - S53 Scheduled Settlement would have a meter/BSS window closing 5 days prior to posting date (OD +48)
   - S120 Scheduled Settlement would have a meter/BSS window closing 10 days prior to posting date (OD + 110)
   **Benefit:** Moving the meter/BSS windows up to 5 days before the S53 settlement run, and 10 days before the S120 settlement run will allow time for SPP to work with the MP/MA to clean up the data as much as possible prior to the 2nd
and 3rd Scheduled Settlements. This will enable SPP to process and validate settlement runs sooner in order to be ready for postings that occur on Mondays (and holidays).

3. Align the 3rd Scheduled Settlement posting so that it falls 30 days after the MP dispute deadline to remove the need for Resettlements – means dispute deadline moves to OD+90 days.
   **Benefit:** Resettlements should be a ‘rare’ occurrence and be an indication of a system issue rather than a normal part of the settlement process
   - Since IM began, almost 100% of Operating Days have been resettled due to meter data revisions.

By adding a 3rd Scheduled Settlement run, we are not increasing the number of settlement runs – but recognizing the need for a 3rd (S120) run to address meter data revisions. We are already doing it now – we just aren’t treating it like part of the normal process by managing it outside the defined settlement postings. This adds a burden for all involved, both SPP and MPs, in order to manage this ‘ad-hoc’ process.

4. Criteria for Resettlement would be updated to greatly restrict the use of them to extraordinary events (*similar to MISO language*) such as (materiality to be defined in the protocols):
   a. SPP Software or SPP Data error impacting MP’s Settlement Statements:
      i. Identified within 90 days of the operating day; or
      ii. Related to the incremental differences after the S53 and identified within 30 days after the Settlement Statement posting; or
   b. A granted dispute for an S7 or S53 that was not resolved in an S120; or
   c. A dispute resulting from the S120 Scheduled Settlement, or an ad-hoc resettlement (these would be limited to only the incremental differences and subject to materiality as described in the dispute section, and must be submitted no later than 30 days after the Settlement Statement posting); or
   d. Per court order or FERC order

5. Resettlements would no longer have defined Settlement Statement posting dates every 30 days after the final settlement run (OD +47), but would instead be referred to based on the number of days after the Operating Day (R150; resettlement run that posts 150 days after the Operating Day)
   **Benefit:** Removing the defined timelines around Settlement Statement postings of resettlements runs will provide more flexibility for the replacement Market Settlement system and enable ‘batching’ of settlement runs when a resettlement is required (for an extraordinary event as noted above in #4)

6. Change the ‘naming convention’ of the runs to S7, S53, S120 to add more clarity to the timeline/process rather than something like the current naming convention of Initial and Final.

7. Target implementation coincidental to the market settlement system replacement currently scheduled for Q2 2019.

**COMMENTS**

The RTWG made non substantive changes to the proposed Tariff language.

Date: 2/22/2018

Action: Motion by Jessica Meyer (LES) seconded by Jim Bixby (ITC) to approve RTWG comments on RR 259 as modified. The motion passed.

**PROPOSED REVISION**

*Provide proposed modifications (redlined) to the revision request for which you are providing comments. Use language from the revision request and redline with your additional edits.*

**SPP Tariff (OATT)**

**Attachment AE**
1.1 Definitions D

**Data Error**

For purposes of this Attachment AE, a data error shall be the following:

(i) Data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is inaccurately modified by the Transmission Provider during the execution of a market function; or

(ii) Anomalous data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is patently incorrect and is used by the Transmission Provider during the execution of a market function; or

(iii) Incorrect data produced and used by the Transmission Provider during the execution of a market function.

1.1 Definitions R

**Resettlement**

The settlement of an Operating Day subsequent to the posting of the S120 Scheduled Settlement for that Operating Day.

1.1 Definitions S

**Settlement Invoice**

A weekly summary of the Integrated Marketplace net daily charges and payments by Asset Owner and Operating Day that is generated for each Market Participant and contains data for all of the Operating Days settled, either on an initial, final Scheduled Settlement or Resettlement basis, during the invoice period. For each Operating Day, only the net amounts (current total less previously invoiced – excluding the S7 Scheduled Settlement) contribute to the invoice amounts.

**Settlement Statement**

A daily summary of the Integrated Marketplace total daily charges and payments by charge type, Asset Owner and Operating Day which is generated for each Market Participant and contains data for all of the Operating Days settled, either on a Scheduled Settlement or Resettlement basis, on that day. For each Operating Day, the current, previous and net amounts are included on the statement.
**Software Error**
For purposes of this Attachment AE, a software error is a software execution that is inconsistent with the requirements of this Attachment AE.

**Scheduled Settlement**
The mandatory Settlement of an Operating Day that is posted on a prescribed schedule.

**Scheduled Settlement Statement**
The statement produced from a Scheduled Settlement.

**S7 Scheduled Settlement Statement**
As defined in Section 10.1(1) of this Attachment AE.

**S53 Scheduled Settlement Statement**
As defined in Section 10.1(2) of this Attachment AE.

**S120 Scheduled Settlement Statement**
As defined in Section 10.1(3) of this Attachment AE.

### 6.1.2.1 Determination of Non-Discriminatory Manual Resource Selection

The Market Monitor shall verify that the process used by the Transmission Provider and local transmission operator to manually select Resources in response to a reliability issue was performed in a non-discriminatory manner. Such verification shall be performed as follows:

(i) The Market Monitor’s evaluation of whether the Transmission Provider’s selection process was non-discriminatory shall consider the cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the Transmission Provider manually committed Resources to resolve the same reliability issue. The Transmission Provider’s
manual commitment of a Resource to resolve a reliability issue shall be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively and economically mitigated the reliability issue, as verified by the Market Monitor.

(ii) The Market Monitor’s evaluation of whether the local transmission operator’s selection process was non-discriminatory shall consider the cost, any affiliation with selected Resources, resource operating parameters, availability of non-selected Resources relative to the selected Resources and any prior instances where the local transmission operator committed Resources to resolve the same Local Emergency Condition. The manual commitment of a Resource by a local transmission operator to resolve a Local Emergency Condition shall be considered non-discriminatory if the Resource selection was made without regard to ownership and the selected Resource effectively mitigated the Local Emergency Condition, as verified by the Market Monitor.

(iii) The Market Monitor shall obtain the necessary information to perform the verification from submitted Resource Offer parameters (cost, operating parameters, availability of non-selected Resources), Market Participant registration (Resource ownership, affiliation), and the Transmission Provider and/or local transmission operator (prior commitments, other Resources considered to resolve the reliability issue or Local Emergency Condition). The Market Monitor shall perform such verification as soon as the necessary information is available, but by no later than the day on which final S120 Scheduled Settlement Statements are issued for the Operating Day in which the manual commitment occurred, as set forth in Section 8.0 and 10.1 of Attachment AE of this Tariff.

8.0 Post Operating Day and Settlement Activities

Post Operating Day activities begin on the day immediately following the Operating Day. The Transmission Provider issues initial Scheduled Settlement Statements for each Operating Day based on the Settlement Statement process outlined in Section 10.1 of this Attachment AE on the seventh (7) day following the Operating Day and final Settlement Statements on the forty-seventh (47) day following the Operating Day to both Asset Owners and Market Participants. Settlement Invoices are issued to Market Participants on a weekly basis.

8.2 Bilateral Settlement Schedules, GFA Carve Outs and FSE
Market Participants may create Bilateral Settlement Schedules for Energy and Operating Reserve obligations by registering and confirming the parameters of the agreement between buyer and seller as described in the Market Protocols. Both the buyer and seller must confirm the Bilateral Settlement Schedule except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under Section 8.2.1 of this Attachment AE. Either the buyer or seller may terminate the Bilateral Settlement Schedule at any time except when the Bilateral Settlement Schedule is associated with an existing bilateral agreement under Section 8.2.1 of this Attachment AE.

Market Participants may submit Bilateral Settlement Schedule quantities for Energy and Operating Reserve obligation for use in the Day-Ahead Market and may submit Bilateral Settlement Schedule quantities for Energy for use in the Real-Time Balancing Market based on settlement timelines for data submittal defined in the Market Protocols up to four (4) days following the applicable Operating Day for the initial settlement. New submittals and revisions to previously submitted values may be submitted up to forty-four (44) days following the applicable Operating Day to be included in the final settlement. Submittals not confirmed by both parties will not be included in any settlement execution.

8.4 Price Corrections

There may be instances in which software errors and/or data errors affect the prices in a manner that is inconsistent with economic efficiency. If such an instance occurs, price corrections in the Day-Ahead and Real-Time Balancing Markets may be performed in accordance with paragraph (21) of this Section 8.4 of this Attachment AE.

(1) For purposes of this section, a "data error" shall be defined as:

(a) Data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party, that is inaccurately modified by the Transmission Provider during the execution of a market function; or

(a) Anomalous data received by the Transmission Provider from an independent source, including data produced by a system or submitted by a third party that is patently incorrect and is used by the Transmission Provider during the execution of a market function; or

(b) Incorrect data produced and used by the Transmission Provider during the execution of a market function.
For purposes of this section, a "software error" shall be defined as a software execution that is inconsistent with this Attachment AE.

The Transmission Provider, in its sole discretion, may make LMP and MCP corrections, and such corrections shall be made in accordance with this Section 8.4. Such price corrections may only be performed if the underlying causes result in a significant Day-Ahead or Real-Time Balancing Market impact. In the exercise of its discretion pursuant to this Section 8.4, the Transmission Provider may consider all relevant facts, including, but not limited to, the degree of the economic impact to the market results in terms of production cost. For purposes of this section, "production cost" is defined as the settlement cost for the market and can be calculated as the sum of the cleared MW * LMP plus cleared OR * MCP plus Start-Up and No-Load costs for all Resources.

If the Transmission Provider, in its sole discretion, determines that an error requiring correction has occurred, the Transmission Provider shall address such errors in accordance with the following procedures:

(a) The Transmission Provider shall notify Market Participants of the contemplated price correction.

(b) If the Transmission Provider provides the notification described in (3)(a) later than 1700 hours five (5) calendar days following the operating day in which the LMPs and MCPs would be affected by the contemplated price correction, the Transmission Provider shall request Commission approval prior to making the price correction.

(c) If the Transmission Provider performs a price correction for the Day-Ahead Market, it shall recalculate LMPs, MCPs, and Day-Ahead Market cleared amounts in a manner that reflects, as closely as practicable, the LMPs and MCPs that would have resulted but for the relevant Software Error or Data Error while maintaining the original Day-Ahead Market unit commitment. The Transmission Provider shall perform any necessary resettlement using the recalculated Day-Ahead Market results. Such recalculated Day-Ahead Market results shall be provided to Market Participants in the same manner as the original Day-Ahead Market results determined in the ordinary course of business.
(d) If the Transmission Provider performs a price correction for the RTBM, it shall recalculate LMPs and MCPs for the RTBM in a manner that reflects, as closely as practicable, the LMPs and MCPs that would have resulted but for the relevant Software Error or Data Error and shall perform any necessary resettlement using these recalculated values. Such recalculated LMPs and MCPs shall be provided to Market Participants in the same manner as LMPs and MCPs determined in the ordinary course of business. Compensation to Market Participants in connection with recalculated prices in the RTBM shall be as follows:

(i) For instances where the recalculated RTBM LMP is less than a Resource’s Energy Offer Curve price, compensation shall be as described under Section 8.6.6(1) of this Attachment AE;

(ii) For instances where a Resource’s recalculated RTBM LMP is greater than the Day-Ahead Market LMP and the Market Participant is buying back its Day-Ahead Market position as a result of a Dispatch Instruction, compensation shall be as described under Section 8.6.6(2) of this Attachment AE except that the MW amount eligible for compensation shall be equal to the difference between the Resource’s Day-Ahead Market MW position and the greater of (1) that Resource’s actual MW output in the Dispatch Interval or (2) the Resource’s average Setpoint Instruction in the Dispatch Interval;

(iii) For instances where a Resource’s recalculated RTBM Operating Reserve product MCP is greater than the Day-Ahead Market Operating Reserve product MCP and the Market Participant is buying back its Day-Ahead Market Operating Reserve product position resulting from the Transmission Provider clearing all or a portion of that Operating Reserve product on a different Resource in the market solution, compensation shall be as described under Section 8.6.6(3) of this Attachment AE.

10.1 Settlement Statements

(1) The Transmission Provider shall issue a preliminary Scheduled Settlement Statement or a preliminary Scheduled Settlement Statement for an Operating Day no later than seven (7) calendar days following the applicable Operating Day unless the seventh (7) day
following the applicable Operating Day is not a business day, in which case, the preliminary S7 Scheduled Settlement Statement shall be issued on the first business day thereafter.  This preliminary Scheduled Settlement Statement is defined as an S7 Scheduled Settlement Statement.

(2) The Transmission Provider shall issue a second Scheduled Settlement Statement for an Operating Day no later than fifty-three (53) calendar days following the applicable Operating Day unless the fifty-third (53rd) calendar day following the applicable Operating Day is not a business day, in which case, the S53 Scheduled Settlement Statement shall be issued on the first business day thereafter.  This second Scheduled Settlement Statement is defined as an S53 Scheduled Settlement Statement.

(3) The Transmission Provider shall issue a final Scheduled Settlement Statement for an Operating Day no later than one hundred and twenty (120) calendar days following the applicable Operating Day unless the one hundred and twentieth (120th) calendar day following the applicable Operating Day is not a business day, in which case, the S120 Scheduled Settlement Statement shall be issued on the first business day thereafter.  This final Scheduled Settlement Statement is defined as an S120 Scheduled Settlement Statement.

The Transmission Provider shall issue a final Settlement Statement for an Operating Day no later than forty-seven (47) calendar days following the applicable Operating Day unless the forty-seventh (47) calendar day following the applicable Operating Day is not a business day, in which case, the final Settlement Statement shall be issued on the first (1) business day thereafter.

(34) The Transmission Provider shall make corrections to the preliminary and final Settlement Statements for an Operating Day for Data Errors, Software Errors, and Settlement Statement disputes in accordance with Section 10.1.1 of this Attachment AE that have been resolved.  Settlement associated with a specific Operating Day shall be considered final at the end of the three hundred sixty-fifth (365) calendar day following the applicable Operating Day.

(45) To the extent that a Market Participant, or its designated Meter Agent, does not submit meter data representing that Market Participant’s actual Resource output and load consumption, either on a five (5) minute basis or an hourly basis in accordance with the timelines specified in the Market Protocols, the Transmission Provider shall use estimated data for that Market Participant that is equal to that Market Participant’s telemetered
generation and load for the applicable intervals or State Estimator values if telemetered values are not available for the purposes of calculating the preliminary statements specified under Sections 10.1(1) of this Attachment AE. To the extent a Meter Agent does not submit data representing the metering of each interconnecting tie-line between Settlement Areas, the Transmission Provider will substitute State Estimator values. In the event that actual meter data is not submitted prior to the issuance of a final S120 Scheduled Settlement Statement, the Transmission Provider shall use the best available data, which may include estimated meter data as developed by the Transmission Provider, for the purposes of calculating final S120 Scheduled Settlement Statements.

(56) The Transmission Provider shall remove from the GFA Responsible Entity’s Settlement Statement all charges associated with the cost of congestion and the cost of losses for GFA Carve Out transactions based on the Day-Ahead Market for the designated Settlement Locations, as set forth in Section 8.2.2 of this Attachment AE. The Transmission Provider removal of all charges associated with the cost of congestion and the cost of losses for GFA Carve Out is subject to the GFA Responsible Entity’s compliance with the requirements of Section 8.2.2.1 of this Attachment AE.

(67) The Transmission Provider shall remove from Western-UGP’s Settlement Statement all charges associated with the cost of congestion and the cost of losses for FSE transactions based on the Day-Ahead Market for the designated Settlement Locations, as set forth in Section 8.2.3 of this Attachment AE. Such removal is subject to Western-UGP’s compliance with the requirements of Section 8.2.3.1 of this Attachment AE.

10.1.1 Resettlements

Resettlements for a given Operating Day shall be considered by the Transmission Provider for the following reasons:

(1) Software Errors and Data Errors

(a) The Transmission Provider, in its discretion, may correct SPP's Software Errors and/or SPP Data Errors and resettle the relevant Operating Day(s), as closely as practicable, to the outcome that would have resulted but for the relevant Software Error or Data Error based on the following:
(i) Software Errors and/or Data Errors that are identified by the Transmission Provider or submitted through the dispute process within ninety (90) calendar days of the affected Operating Day will be considered for resettlement.

(ii) Software Errors and/or Data Errors that result in incremental differences between any two consecutive Settlement Statements subsequent to S7 Scheduled Settlement Statement will be considered for resettlement if identified by the Transmission Provider or submitted through the dispute process within thirty (30) calendar days of the posting of the applicable Settlement Statement.

(b) If the correction of the relevant Software Error and/or Data Error would require Day-Ahead or Real-Time Balancing Market price corrections, the Transmission Provider will address such errors in accordance with the procedures in Section 8.4 of this Attachment AE.

(2) Granted Disputes

a. The Transmission Provider will resettle Operating Days for a granted dispute in accordance with the guidelines in Section 10.3 of this Attachment AE.

(3) Per FERC or court order:

a. The Transmission Provider will resettle Operating Days as required by FERC or court order.

10.3 Invoice Disputes

In the event that a dispute arises between the Market Participant and the Transmission Provider concerning any initial, final or resettlement Settlement Statements contained within an invoice that cannot be resolved to the Market Participant’s satisfaction, such disputes shall be resolved as follows:

(1) In the case of a dispute relating to Disputes relating to an S7 Scheduled Settlement Statement or S53 an initial or final Scheduled Settlement Statement:

a. The Market Participant must notify the Transmission Provider within ninety (90) calendar days of the applicable Operating Day following the issue date of the applicable invoice of the items that the Market Participant wishes to dispute.

(2) Disputes relating to the S120 Scheduled Settlement Statement, or any subsequent Settlement Statement:
a. Must relate only to material incremental changes in data that occurred between issuance of the relevant consecutive Settlement Statements. Material for the purpose of this section is defined as a dispute wherein more than $2,000.00 is at issue for the Market Participant for the impacted Operating Day. The Market Participant must submit documentation supporting the materiality of the dispute for consideration.

b. Must be filed within thirty (30) calendar days following the posting of the applicable Settlement Statement that the Market Participant wishes to dispute.

(2)(3) The notice of dispute must contain the following minimum information:

- Request Type
- Subject
- Full Description
- Statement Type
- Charge Type
- Settlement Location
- Operating Day
- Start Interval
- End Interval
- Dispute Amount
- Proposed Resolution
- Market Participant
- Asset Owner

(32) If the Transmission Provider determines that additional information is required concerning a submitted notice of dispute, the Transmission Provider shall notify the Market Participant no later than thirty (30) days following the date the notice of dispute was submitted to the Transmission Provider. The Market Participant must then submit additional information to the Transmission Provider within thirty (30) days in order to have the notice of dispute considered valid.

(43) The Transmission Provider shall use its best efforts to notify the Market Participant of approval or denial of the submitted notice of dispute within twenty (20) business days following the close of the applicable ninety (90) day or thirty (30) day window specified under Subsection 10.3(1) or Subsection 10.3(2). If the Transmission Provider estimates that it will take longer than the twenty (20) business day window to analyze a specific
If the Transmission Provider denies a Market Participant’s notice of dispute or the Market Participant is not satisfied that it is receiving timely consideration of the dispute, the Market Participant may initiate the dispute resolution procedures specified under Section 12 of the Tariff.

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<td>Minimum Transmission Design Standards for Competitive Upgrades (MTDS)</td>
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Revision Request Recommendation Report

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<th>Date: 11/14/2017</th>
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**SUBMITTER INFORMATION**

<table>
<thead>
<tr>
<th>Submitter Name: Ryan Kirk</th>
<th>Company: AEP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Email: <a href="mailto:rkirk@aep.com">rkirk@aep.com</a></td>
<td>Phone: 614.716.6251</td>
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</table>

**EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION**

**OBJECTIVE OF REVISION**

**Objectives of Revision Request:**

*Describe the problem/issue this revision request will resolve.*

A need has been identified for SPP to have the option to assign an Out-of-Merit Energy (OOME) cap and/or floor, in addition to the current ability to assign a fixed dispatch MW. This change will allow Resources operating under an OOME cap and/or floor to be economically dispatched up to and including the OOME limits. Under the current method of assigning a fixed OOME MW, Resources are not able to be dispatched economically by SCED (even when being dispatched would help the situation for which an OOME has been issued). If SPP needs a positively impacting Resource to remain above a certain output, SPP currently must assign a fixed OOME MW value to keep the Resource at a specific level. This RR would allow SPP to manually set a floor for the dispatch and allow SCED to dispatch the Resource up and/or down to this OOME floor. The same would apply to a Resource negatively affecting a flowgate. SPP needs the Resource to remain below a certain value. This RR would allow SPP to manually set a cap for the dispatch and allow SCED to economically dispatch the Resource down and/or up to the OOME cap.

Language is added to 4.4.2.5 to define SPP’s ability to place an OOME maximum and/or minimum MW on a Resource during an OOME event. Language is also added to 4.5.9.9 to include the OOME cap and floor in the MWP considerations for Resources that are issued an OOME.

*Describe the benefits that will be realized from this revision.*

This change will allow Resources operating under an OOME cap and/or floor to be economically dispatched up to and including the newly defined OOME limits.

**SPP STAFF ASSESSMENT**

**IMPACT**

Will the revision result in system changes □ No ☒ Yes

Summarize changes:

Will the revision result in process changes? □ No ☒ Yes

Summarize changes:
Is an Impact Assessment required? ☒ No  ☑ Yes

If no, explain:

<table>
<thead>
<tr>
<th>Estimated Cost: $</th>
<th>Estimated Duration: months</th>
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Primary Working Group Score/Priority:

<table>
<thead>
<tr>
<th>SPP DOCUMENTS IMPACTED</th>
</tr>
</thead>
<tbody>
<tr>
<td>☑ Market Protocols</td>
</tr>
<tr>
<td>Protocol Section(s): 4.4.2.5, 4.4.2.5.1 (new), 4.4.2.5.2 (new), 4.4.2.5.3 (new), 4.5.9.9</td>
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<tr>
<td>Protocol Version: 50a</td>
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<thead>
<tr>
<th>Operating Criteria</th>
<th>Criteria Section(s):</th>
<th>Criteria Date:</th>
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<tr>
<td>Planning Criteria</td>
<td>Criteria Section(s):</td>
<td>Criteria Date:</td>
</tr>
<tr>
<td>☑ Tariff</td>
<td>Tariff Section(s): Attachment AE – 6.2.4</td>
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<tr>
<th>Business Practice Number:</th>
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<table>
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<tr>
<th>Integrated Planning Model (ITP Manual)</th>
<th>Section(s):</th>
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<tr>
<th>Revision Request Process</th>
<th>Section(s):</th>
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<tr>
<th>Minimum Transmission Design Standards for Competitive Upgrades (MTDS)</th>
<th>Section(s):</th>
</tr>
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<tr>
<th>Reliability Coordinator and Balancing Authority Data Specifications (RDS)</th>
<th>Section(s):</th>
</tr>
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</table>

<table>
<thead>
<tr>
<th>SPP Communications Protocols</th>
<th>Section(s):</th>
</tr>
</thead>
</table>

WORKING GROUP REVIEWS AND RECOMMENDATIONS
List Primary and any Secondary/Impacted WG Recommendations as appropriate

<table>
<thead>
<tr>
<th>Primary Working Group: MWG</th>
<th>Date: 11/14/2017</th>
</tr>
</thead>
<tbody>
<tr>
<td>Action Taken: Approved</td>
<td></td>
</tr>
<tr>
<td>Abstained: WR</td>
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</table>

<table>
<thead>
<tr>
<th>Date: 1/8/2018</th>
</tr>
</thead>
<tbody>
<tr>
<td>Action Taken: Approved SPP Comments as modified by the MWG</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Date: 2/6/2018</th>
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</thead>
<tbody>
<tr>
<td>Action Taken: Unanimously Approved Impact Analysis with a Medium Rank</td>
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</table>

<table>
<thead>
<tr>
<th>Secondary Working Group: ORWG</th>
<th>Date: 3/1/2018</th>
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</thead>
<tbody>
<tr>
<td>Action Taken:</td>
<td></td>
</tr>
<tr>
<td>Abstained:</td>
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</tr>
<tr>
<td>Opposed:</td>
<td></td>
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</tbody>
</table>

Reasons for Opposition:
| Secondary Working Group: RTWG | Date: 2/22/2018  
|                               | Action Taken: To approve RR 252  
|                               | Abstained: Westar  
|                               | Opposed: None |

**Reasons for Opposition:**

<table>
<thead>
<tr>
<th>Secondary Working Group: RCWG</th>
<th>Date: 3/12/2018</th>
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<td>Abstained:</td>
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<td>Opposed:</td>
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**Reasons for Opposition:**

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<td>Action Taken:</td>
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<td>Abstained:</td>
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<td></td>
<td>Opposed:</td>
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**Reasons for Opposition:**

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<th>BOD/Member Committee</th>
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<td></td>
<td>Abstained:</td>
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<td></td>
<td>Opposed:</td>
</tr>
</tbody>
</table>

**Reasons for Opposition:**

<table>
<thead>
<tr>
<th>COMMENTS</th>
</tr>
</thead>
</table>

**Comment Author:** MWG

**Date Comments Submitted:** 11/14/2017

**Description of Comments:** MWG approved RR252 with modifications to Protocols and Tariff that clarified that the OOME may specify either the fixed MW level or an OOME cap and/or floor.

**Status:** Approved and incorporated language.
**COMMENTS**

<table>
<thead>
<tr>
<th>Comment Author: Ron Gunderson on behalf of NPPD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date Comments Submitted: 11/27/2017</td>
</tr>
<tr>
<td>Description of Comments: Proposed additional clarifying changes to section 4.4.2.5 that did not change the intent of the RR.</td>
</tr>
<tr>
<td>Status: Reviewed and not incorporated by the MWG on 1/8/2018</td>
</tr>
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</table>

**COMMENTS**

<table>
<thead>
<tr>
<th>Comment Author: John Luallen on behalf of SPP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date Comments Submitted: 1/4/2018</td>
</tr>
<tr>
<td>Description of Comments: SPP staff added necessary settlement changes in Section 4.5.9.9 (Real-Time Out-of-Merit Amount), to reflect the proposed OOME cap and/or OOME floor. Staff also added enhanced clarity in Section 4.5.9 (Real-Time Settlements Amount) located in the Protocols and Section 8.6.6 (Real-Time Out-of-Merit Amount) located in Attachment AE of the SPP Tariff. Staff also addressed NPPD’s concerns with the language in 4.4.2.5.1(1)(c)(i) that describes how the current systems work today.</td>
</tr>
<tr>
<td>Status: Approved and incorporated by the MWG on 1/8/2018</td>
</tr>
</tbody>
</table>

**COMMENTS**

<table>
<thead>
<tr>
<th>Comment Author: MWG</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date Comments Submitted: 1/8/2018</td>
</tr>
<tr>
<td>Description of Comments: The MWG made modifications to the SPP comments submitted on 1/4/2018 during the January 8-9, 2018 meeting. The MWG modified Section 4.4.2.5.2 of the Protocols to add clarification to the language specific to Dispatch Instruction notification, and Emergency Minimum and Maximum limits. The adjustment in AE Section 6.2.4, aligns the Tariff with the Protocols related to when a local transmission operator issues an OOME.</td>
</tr>
<tr>
<td>Status: Approved and incorporated by the MWG on 1/8/2018</td>
</tr>
</tbody>
</table>

**PROPOSED REVISION(S) TO SPP DOCUMENTS**

**Market Protocols**

### 4.4.2.5 Out-of-Merit Energy (OOME) Dispatch

SPP may issue an OOME to any Resource not on outage. An OOME will specify **either the a fixed MW level or an OOME cap and/or OOME floor** MW level the Resource is expected to produce until such time as the issue can be resolved. **When an OOME contains a fixed OOME MW, the Resource is instructed to generate equal to the specified fixed OOME MW. When an OOME contains an OOME cap MW and/or OOME floor MW, the resource is instructed to generate below the OOME cap MW and/or above the OOME floor MW respectively.** Such MW levels may
include (i) dispatch below a Resource’s Minimum Economic Capacity Operating Limit down to Minimum Normal Capacity Operating Limit or Minimum Emergency Capacity Operating Limit as system conditions warrant or (ii) dispatch above a Resource’s Maximum Economic Capacity Operating Limit up to Maximum Normal Capacity Operating Limit or Maximum Emergency Capacity Operating Limit as system conditions warrant. During the period of time an OOME is imposed, the Resource will not be eligible to clear Operating Reserves. SPP will make every effort to define and activate the appropriate constraint(s). A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may be issued OOMEs only during an Emergency Condition or a reliability issue equivalent to a TLR 5 or greater. A local transmission operator may 1) request the Transmission Provider to issue an OOME, or 2) issue an OOME directly to the Resource(s). If the local transmission operator determines there is an adequate amount of time prior to issuing the OOME directly to the Resource, the transmission operator will coordinate with SPP to ensure the OOME is provided by SPP. If the initial OOME is issued by the local transmission operator, the local transmission operator shall coordinate with SPP to ensure subsequent OOMEs are provided by SPP. _An OOME issued directly by the local transmission operator may also specify either a fixed MW level or an OOME cap and/or OOME floor MW level._

### 4.4.2.5.1 Fixed OOME

1. During the period of time when a **fixed** OOME is imposed, SPP will ensure that the following occurs:

   (a) A notification is immediately issued containing a Dispatch Instruction equal to the **fixed** MW level the Resource is instructed to produce and the OOME flag is set equal to “True”;

   (b) Setpoint Instructions and Economic/Emergency Minimum and Economic/Emergency Maximum Limits for the current Dispatch Interval are immediately adjusted to the **fixed** MW level the Resource is instructed to produce;

   (i) For VERs, the Economic/Emergency Minimum and Economic/Emergency Maximum Limits for the current Dispatch Interval are immediately adjusted to the **fixed** MW level the Resource is instructed to produce and the Setpoint Instructions will be immediately adjusted to the lesser of the **fixed** MW level the Resource is instructed to produce or the echo of the actual SCADA;
(c) Setpoint Instructions for future intervals and Economic/Emergency Minimum and Economic/Emergency Maximum limits not yet dispatched will be set to the fixed MW level the resource is instructed to produce;

(i) For VERs, the Economic/Emergency Minimum and Economic/Emergency Maximum limits not yet dispatched will be set to the MW level the Resource is instructed to produce and the Setpoint Instructions will be set to the lesser of the fixed MW level the Resource is instructed to produce or the echo of actual SCADA output; and

(d) SPP systematically notifies the Market Participant when the OOME has ended.

4.4.2.5.2 OOME Cap and OOME Floor

(1) During the period of time when an OOME contains an OOME cap and/or OOME floor, SPP will ensure that the following occurs:

(a) A notification is immediately issued containing a Dispatch Instruction as defined in (i) to (iii) below and the OOME flag is set equal to “True”:
   (i) If the current Dispatch Instruction is greater than the OOME cap MW, the Dispatch Instruction will be adjusted to the OOME cap MW;
   (ii) If the current Dispatch Instruction is less than the OOME floor MW, the Dispatch Instruction will be adjusted to the OOME floor MW;
   (iii) If the current Dispatch Instruction is less than or equal to the OOME cap MW and/or greater than or equal to the OOME floor MW, the Dispatch Instruction will not be adjusted;

(b) Setpoint Instructions for the current Dispatch Interval are immediately adjusted:
   (i) If the current Setpoint Instruction is greater than the OOME cap MW, the Setpoint Instruction will be adjusted to the OOME cap MW;
   (ii) If the current Setpoint Instruction is less than the OOME floor MW, the Setpoint Instruction will be adjusted to the OOME floor MW;
   (iii) If the current Setpoint Instruction is less than or equal to the OOME cap MW and/or greater than or equal to the OOME floor MW, the Setpoint Instructions will not be adjusted;

(c) Economic/Emergency Minimum Limits for the current Dispatch Interval are immediately adjusted to the OOME floor MW. Economic/Emergency Maximum Limits for the current Dispatch Interval are immediately adjusted to the OOME cap MW;

(d) For future intervals not yet dispatched the Economic/Emergency Maximum Limits will be set equal to the OOME cap MW. For future intervals
not yet dispatched the Economic/Emergency Minimum Limits will be set equal to the OOME floor MW;

(e) The resource will be dispatchable in RTBM SCED; and

(f) SPP systematically notifies the Market Participant when the OOME has ended;

(2) To the extent that the OOME was initiated directly by a local transmission operator, Market Participants shall be compensated for the period of time the OOME was imposed in accordance with Section 4.5.9.9 as if they had been issued an OOME by SPP; except that if the Market Monitor determines that the Resource selected pursuant to Section 4.4.2.5 was selected by the local transmission operator in a discriminatory manner and the Resource was affiliated with the local transmission operator, such Resource shall not be eligible for compensation under Section 4.5.9.9. Such determination shall be made using the same standards and procedures prescribed for Resource selection in the Intra-Day Reliability Unit Commitment process, as set forth in Section 6.1.2.1 of Attachment AE to the Tariff. Recovery of any compensation shall be collected locally as described under Section 4.5.9.9.

(3) To the extent that the OOME was initiated by SPP at the request of a local transmission operator, such Resources issued OOMEs shall be selected by SPP in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of Attachment AE to the Tariff. In such event, Market Participants shall be compensated for the period of time the OOME was imposed in accordance with Section 4.5.9.9. The recovery of the compensation paid by SPP shall be collected by SPP locally as described under Section 4.5.9.9.

(4) To the extent that the OOME was initiated by SPP, such Resources issued OOMEs shall be selected by SPP in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of Attachment AE to the Tariff. Recovery of compensation for Resources directly issued OOMEs by SPP that are received under Section 4.5.9.9 shall be collected regionally under Section 4.5.12.

(5) SPP, the local transmission operator, and affected Resource owners shall develop operating guides to be applied to OOMEs made to relieve known and recurring reliability issues or to relieve known and recurring Emergency Conditions. Such Resources will be compensated in the same manner as any other Resource that is issued an OOME. The recovery of the compensation paid by SPP under Section 4.5.9.9 shall be collected by SPP locally as described under Section 4.5.9.9.
4.4.2.5.1 — Out-of-Merit Energy During Emergency Conditions

If the OOME is issued to resolve an Emergency Condition, SPP will do the following in addition to the items listed in 4.4.2.5(1):

1) Declare the Emergency Condition as soon as possible by posting it on the SPP OASIS;
2) Communicate the OOME via a phone call; and
3) Displace the OOME with a market solution as soon as possible, consistent with system safety and reliability.

4.5.9 Real-Time Balancing Market Settlement

…

(9) In addition, Resources may receive a Make Whole Payment related to an OOME as described under Section 4.5.9.9, subject to certain eligibility requirements, as follows:

(a) If the Resource is issued an fixed MW level or an OOME cap and/or OOME floor by SPP in any hour that creates Out-of-Merit Energy (OOME) MW in excess of the Resource’s Dispatch Instruction and the Resource Offer costs associated with the OOME MW are greater than the Energy revenue received for the OOME MW, the Resource will receive the difference between the Energy Offer Curve costs associated with the OOME MW and the OOME MW Energy revenue. The OOME MW is calculated as Max (0, or the difference between (i) the (lesser of actual Resource output or the Resource’s floor or fixed OOME MW) and (ii) the Resource’s Desired Dispatch);

(b) If the OOME is for Energy in the down direction and the RTBM LMP is greater than the DA Market LMP, the Asset Owner will receive a credit for the difference multiplied by the OOME MW cap or fixed. The OOME MW is calculated as Max (0, the difference between (i) the Resource’s DA Market cleared Energy MW and (ii) the (greater of actual Resource output or the Resource’s OOME floor or fixed OOME MW)); and

(c) If during the period of time when an OOME is imposed, the RTBM cleared amount of an Operating Reserve product is less than the DA Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the DA Market MCP, the Asset Owner will receive a credit for the difference multiplied by the OOMOR MW. The OOMOR MW is calculated as Max (0, the difference between the Resource’s DA Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW).
Make Whole Payments associated with OOME are collected as part of revenue neutrality uplift as described under Section 4.5.12.

4.5.9.9   Real-Time Out-Of-Merit Amount

(1) An RTBM credit or charge\(^1\) will be made to each Market Participant with a Resource that passes a primary Contingency Reserve deployment test as described under Section 6.1.11.1(3)(b)(i) and/or otherwise receives an OOME from SPP or a local transmission operator that creates a cost to the Asset Owner or that adversely impacts the Asset Owner’s DA Market position and/or if a Market Participant must buy back its DA Market position for any Operating Reserve product at a RTBM MCP that is greater than that product’s DA Market MCP. Resources issued OOMEs by or at the request of a local transmission operator in order to solve a Local Emergency Condition or a Local Reliability Issue are eligible for out-of-merit credits as defined in this Section unless selection of the Resource by the local transmission operator was performed in a discriminatory manner as determined by the MMU and the Resource was an affiliated Resource; however, a manual process is employed for the calculation of the out-of-merit credits and they will appear in the Miscellaneous Amount charge type defined in Section 4.5.11. The cost allocation of out-of-merit credits associated with OOMEs issued by or at the request of a local transmission operator will be determined hourly by multiplying an Asset Owner’s RTBM actual load in the impacted Settlement Area by a rate determined by dividing the daily sum of all out-of-merit credits applicable to the impacted Settlement Area by the daily sum of all Asset Owners’ RTBM actual load in the impacted Settlement Area. A manual process is also employed for these calculations and the charges will appear in the Miscellaneous Amount charge type defined in Section 4.5.11. Out-of-merit credits associated with OOMEs issued directly by SPP to address a reliability issue other than a Local Reliability Issue will be recovered under Section 4.5.12. The amount will be calculated on a Dispatch Interval basis under the following conditions:

(a) If the OOME is for Energy in the up direction and the Energy Offer Curve cost associated with the Out-of-Merit Energy (OOME) floor or fixed MW is greater than the RTBM LMP, the Asset Owner will receive a credit equal to the difference multiplied by the OOME floor or fixed MW. The OOME MW is calculated as Max (0, or the difference between (i) (lesser of the absolute value of the actual Resource

---

\(^1\) Note that this charge type will almost always produce a credit. The charge is included here for the rare occasion when a charge may be produced as a result of a data error and/or a resettlement.
output or the Resource’s OOME floor or fixed MW) and (ii) the Resource’s Desired Dispatch); 

(b) If the OOME is for Energy in the down direction, including a Resource de-commitment or movement of a DA Market committed MCR to a configuration with a lower applicable maximum capacity operating limit and the RTBM LMP is greater than the DA Market LMP, the Asset Owner will receive a credit for the difference multiplied by the OOME MW cap or fixed. The OOME MW is calculated as Max (0, or the difference between (i) the absolute value of the Resource’s DA Market cleared Energy MW and (ii) the (greater of the absolute value of the actual Resource output or the Resource’s OOME cap or fixed MW)); and/or

(c) If an OOME for Energy or Operating Reserve, or a Resource de-commitment instruction or movement of a DA Market committed MCR to a configuration with a lower applicable maximum capacity operating limit, causes the RTBM cleared amount of an Operating Reserve product to be less than the DA Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the DA Market MCP, the Asset Owner will receive a credit for the difference multiplied by the Out-Of-Merit-Operating Reserve (OOMOR) MW. The OOMOR MW is calculated as Max (0, or the difference between the Resource’s DA Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW).

To the extent that additional costs are incurred as a direct result of an OOME through the compensation mechanisms described above, Market Participants may request additional compensation through submittal of actual cost documentation to SPP. SPP will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.

The amount to each Asset Owner (AO) for each eligible Resource Settlement Location for each Dispatch Interval is calculated as follows:

\[
\text{IF } \text{RtOom5minFlg}_{a,s,i} = 1 \text{ OR ResDeCommit5minFlg}_{a,s,i} = 1 \text{ OR } \text{RtReprice5minFlg}_{a,s,i} = 1 \text{ OR } \text{ConfigDeCommit5minFlg}_{a,s,i,t} = 1 \\
\text{THEN }
\]
#RtOom5minAmt_{a,s,i} = (RtOomeIncr5minAmt_{a,s,i} +
RtOomeDecr5minAmt_{a,s,i} +
RtOomor5minAmt_{a,s,i}) \times (-1)

ELSE IF RtDeSelectOr5minFlg_{a,s,i} = 1

THEN

#RtOom5minAmt_{a,s,i} = RtOomor5minAmt_{a,s,i} \times (-1)

ELSE

#RtOom5minAmt_{a,s,i} = 0

Where,

(a)  RtOomeIncr5minAmt_{a,s,i} =

\text{Max} (0, \text{Max} (0, \text{RtOomeIncrEn5minAmt}_{a,s,i} -
\text{RtOomeDesiredEn5minAmt}_{a,s,i}) -
\text{Max} (0, \text{Min} (0, \text{RtBillMtr5minQty}_{a,s,i} ) \times (-1),
\text{Min} (\text{RtOomeFloor5minQty}_{a,s,i}, \text{RtAvgSetpoint5minQty}_{a,s,i})) -
\text{RtOomeDesiredEn5minQty}_{a,s,i}) \times \text{Max}(0, \text{RtLmp5minPrc}_{s,i}) / 12

(a.1)  \#RtOomeIncrEn5minAmt_{a,s,i} =

\int_x^{y} \text{RTBM As Dispatched Energy Offer Curve}

Where:

X = 0
\[ Y = \min \left( \min \left( 0, \text{RtBillMtr5minQty}_{a,s,i} \right) \right) \times (-1), \]

\[ \min \left( \text{RtOomeFloor5minQty}_{a,s,i}, \text{RtAvgSetpoint5minQty}_{a,s,i} \right) \]

(a.2) \#RtOomeDesiredEn5minAmt_{a,s,i} =

\[ \int_y^x \text{RTBM As Dispatched Energy Offer Curve} \]

Where:

\[ X = 0 \]

\[ Y = \text{RtOomeDesiredEn5minQty}_{a,s,i} \]

(b) \text{RtOomeDecr5minAmt}_{a,s,i} =

\[ \max \left( 0, (-1) \times \max \left( \min \left( 0, \text{RtBillMtr5minQty}_{a,s,i} \right) \times (-1), \max \left( \text{RtAvgSetpoint5minQty}_{a,s,i}, \text{RtOomeCap5minQty}_{a,s,i} \right) \right) - \text{DaClrdHrlyQty}_{a,s,h} \right) \]

\[ \times \max \left( 0, \text{RtLmp5minPrc}_{s,i} - \text{DaLmpHrlyPrc}_{s,h} \right) / 12 \]

(c) IF \text{RtOom5minFlg}_{a,s,i} = 1 OR \text{ResDeCommit5minFlg}_{a,s,i} = 1 OR \text{RtReprice5minFlg}_{a,s,i} = 1 OR \text{ConfigDeCommit5minFlg}_{a,s,i,t} = 1

THEN

\[ \text{RtOomor5minAmt}_{a,s,i} = \]

\[ \sum_z \left( \max \left( 0, \sum_z \text{DaRegUpHrlyQty}_{a,z,s,h} - \text{RtRegUp5minQty}_{a,z,s,i} \right) \right) \]

\[ \times \max \left( 0, \text{RtRegUpMcp5minPrc}_{z,i} - \text{DaRegUpMcpHrlyPrc}_{z,h} \right) \]

\[ + \left( \max \left( 0, \sum_z \text{DaRegDnHrlyQty}_{a,z,s,h} - \text{RtRegDn5minQty}_{a,z,s,i} \right) \right) \]
\[ \begin{align*} & \text{ELSE IF } RtDeSelectOr5minFlg_{a,s,i} = 1 \\
& \quad \text{THEN} \\
& \quad RtOomor5minAmt_{a,s,i} = \\
& \quad \sum_{z} \left( (\text{Max} \left( 0, \sum_{z} \text{DaRegUpHrlyQty}_{a,z,s,h} - \text{RtRegUp5minQty}_{a,z,s,i} \right) \\
& \quad \times \text{Max} \left( 0, \text{RtRegUpMcp5minPrc}_{z,i} - \text{DaRegUpMcpHrlyPrc}_{z,h} \right) \right) \\
& \quad + (\sum_{z} \text{DaRegDnHrlyQty}_{a,z,s,h} - \text{RtRegDn5minQty}_{a,z,s,i}) \\
& \quad \times \text{Max} \left( 0, \text{RtRegDnMcp5minPrc}_{z,i} - \text{DaRegDnMcpHrlyPrc}_{z,h} \right) \right) \\
& \quad + ((\text{Max} \left( 0, \sum_{z} \text{DaSpinHrlyQty}_{a,z,s,h} - \text{RtSpin5minQty}_{a,z,s,i} \right) \\
& \quad \times \text{Max} \left( 0, \text{RtSpinMcp5minPrc}_{z,i} - \text{DaSpinMcpHrlyPrc}_{z,h} \right) \right) \\
& \quad + ((\sum_{z} \text{DaSuppHrlyQty}_{a,z,s,h} - \text{RtSupp5minQty}_{a,z,s,i}) \\
& \quad \times \text{Max} \left( 0, \text{RtSuppMcp5minPrc}_{z,i} - \text{DaSuppMcpHrlyPrc}_{z,h} \right) \right) / 12 \end{align*} \]
\[ + \left( \text{Max } (0, \sum_{i} \text{DaSuppHrlyQty}_{a,z,s,h} - \text{RtSupp5minQty}_{a,z,s,i}) \right) \]
\[ \times \text{Max } (0, \text{RtSuppMcp5minPrc}_{z,i} - \text{DaSuppMcpHrlyPrc}_{z,h}) \]
\[ \times \text{RtDeSelectSupp5minFlg}_{a,s,i} \] / 12

(2) For each Asset Owner, an hourly amount is calculated at each Settlement Location. The hourly amount is calculated as follows:

\[ \text{RtOomHrlyAmt}_{a,s,h} = \sum_{i} \text{RtOom5minAmt}_{a,s,i} \]

(3) For each Asset Owner, a daily amount is calculated at each Settlement Location. The daily credit amount is calculated as follows:

\[ \text{RtOomDlyAmt}_{a,s,d} = \sum_{h} \text{RtOomHrlyAmt}_{a,s,h} \]

(4) For each Asset Owner associated with Market Participant \( m \), a daily amount is calculated. The daily amount is calculated as follows:

\[ \text{RtOomAoAmt}_{a,m,d} = \sum_{s} \text{RtOomDlyAmt}_{a,s,d} \]

(5) For each Market Participant, a daily amount is calculated representing the sum of Asset Owner amounts associated with that Market Participant. The daily amount is calculated as follows:

\[ \text{RtOomMpAmt}_{m,d} = \sum_{a} \text{RtOomAoAmt}_{a,m,d} \]

(6) For FERC Electric Quarterly Reporting ("EQR") purposes, SPP calculates Real-Time Out-of-Merit Energy and Operating Reserve $ per Dispatch Interval for each Asset Owner as follows:

(a) \[ \#EqrRtOom5minPrc_{a,s,i} = (-1) \times \text{RtOom5minAmt}_{a,s,i} \]

(b) IF \( \#EqrRtOom5minPrc_{a,s,i} > 0 \)

THEN

\[ \#EqrRtOom5minQty_{a,s,i} = 1 \]
The above variables are defined as follows:

<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>RtOom5minAmt_{a,s,i}</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Make Whole Payment Amount per AO per Settlement Location per Dispatch Interval - The amount to AO a for eligible Resource Settlement Location s in Dispatch Interval i for Out-of-Merit Energy and Operating Reserve resulting from an OOME.</td>
</tr>
<tr>
<td>RtOomeIncr5minAmt_{a,s,i}</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Incremental Energy Make Whole Payment Amount per AO per Settlement Location per Dispatch Interval - The portion of AO a’s RtOom5minAmt_{a,s,i} amount for eligible Resource Settlement Location s in Dispatch Interval i for Out-of-Merit Energy resulting from an OOME in the up direction.</td>
</tr>
<tr>
<td>RtOomeDecr5minAmt_{a,s,i}</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Decremental Energy Make Whole Payment Amount per AO per Settlement Location per Dispatch Interval - The portion of AO a’s RtOom5minAmt_{a,s,i} amount for eligible Resource Settlement Location s in Dispatch Interval i for Out-of-Merit Energy resulting from an OOME in the down direction.</td>
</tr>
<tr>
<td>ResDeCommit5minFlg_{a,s,i}</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Resource De-Commitment Flag per AO per Dispatch Interval per Settlement Location – The value as described under Section 4.5.9.10.</td>
</tr>
<tr>
<td>ConfigDeCommit5minFlg_{a,s,i,c,t}</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>MCR Configuration De-Commitment Flag per AO per Dispatch Interval per Settlement Location per RUC Make-Whole Payment Eligibility Period per Transition Event – The flag set to 1 by SPP indicating that AO a’s MCR configuration has been de-committed by SPP to a configuration with a lower applicable maximum capacity operating limit than the configuration committed in the DA Market, at MCR Settlement Location s in Dispatch Interval i per transition event t.</td>
</tr>
<tr>
<td>RtOom5minFlg_{a,s,i}</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-of-Merit Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 when an OOME is issued, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>RtReprice5minFlg_{a,s,i}</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Repricing Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 whenever there is a price correction event as described under Section 6.6.1, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>--------------------------</td>
<td>-----------</td>
<td>---------------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtDeSelectOr5minFlg $a, s, i$</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Deselect Operating Reverse Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 whenever an OOME is issued to deselect a Resource for Operating Reserve that was cleared in the Day-Ahead Market, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>RtOomor5minAmt $a, s, i$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Out-Of-Merit Operating Reserve Make Whole Payment Amount per AO per Settlement Location per Dispatch Interval - The portion of AO a’s RtOome5minAmt $a, s, i$ attributable to buying back a DA Market Operating Reserve position in the RTBM at a RTBM MCP that is greater than the corresponding DA Market MCP. This should not be a normal occurrence but could happen as a result of price corrections as described under Section 6.6.1.</td>
</tr>
<tr>
<td>RtOomeDesiredEn5minQty $a, s, i$</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time OOME Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval – The Desired Dispatch MW for AO a’s eligible Resource for Dispatch Interval i at RtLmp5minPrc $s, i$ as calculated from the Resource’s As Dispatched Energy Offer Curve using the As-Dispatched Minimum Capacity Limit (Economic or Regulating, as applicable) in place prior to the issuance of the OOME as an output floor and the As-Dispatched Maximum Capacity Limit (Economic or Regulating, as applicable) in place prior to the issuance of the OOME as an output ceiling.</td>
</tr>
<tr>
<td>RtOomeIncrEn5minAmt $a, s, i$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time OOME Incremental Energy Cost Amount per AO per Settlement Location per Dispatch Interval - The average incremental energy offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i as calculated from the Resource’s As Dispatched Energy Offer Curve from 0 MW to the lesser of the OOME MW or RtBillMtr5minQty $a, s, i$.</td>
</tr>
<tr>
<td>RtOomeDesiredEn5minAmt $a, s, i$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time OOME Energy Cost at Desired Dispatch Quantity per AO per Settlement Location per Dispatch Interval - The average incremental energy offer cost, in dollars, associated with AO a’s eligible Resource at Settlement Location s for Dispatch Interval i as calculated from the Resource’s As Dispatched Energy Offer Curve from 0 MW to RtOomeDesiredEn5minQty $a, s, i$.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
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</tr>
<tr>
<td>RtAvgSetPoint5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Average Setpoint Instruction MW per AO per Settlement Location per Dispatch Interval – The value described under Section 4.5.9.8 except that when RtOom5minFlg_{a,s,i} is set to 1, RtAvgSetPoint5minQty_{a,s,i} is set equal to the OOME MW.</td>
</tr>
<tr>
<td>RtBillMtr5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Actual Meter Quantity per AO per Location per Dispatch Interval - The value defined under Section 4.5.9.1 for Dispatch Interval i.</td>
</tr>
<tr>
<td>RtOomeFloor5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time OOME Floor MW per AO per Settlement Location per Dispatch Interval – The MW floor for an out-of-merit dispatch instruction as defined in section 4.4.2.5.2.</td>
</tr>
<tr>
<td>RtOomeCap5minQty_{a,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time OOME Cap MW per AO per Settlement Location per Dispatch Interval – The MW cap for an out-of-merit dispatch instruction as defined in section 4.4.2.5.2.</td>
</tr>
<tr>
<td>RtLmp5minPrc_{s,i}</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time LMP - The value defined under Section 4.5.9.1 at Settlement Location s for Dispatch Interval i.</td>
</tr>
<tr>
<td>DaClrdHrlyQty_{a,s,h}</td>
<td>MWh</td>
<td>Hour</td>
<td>Day-Ahead Cleared Energy Quantity per AO per Settlement Location per Hour in the DA Market – The value described under Section 4.5.8.1.</td>
</tr>
<tr>
<td>DaRegUpHrlQty_{a,z,s,h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Operational Regulation-Up Service Quantity per AO per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>DaRegDnHrlQty_{a,z,s,h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Service Quantity per AO per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>DaSpinHrlyQty_{a,z,s,h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Quantity per AO per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.6.</td>
</tr>
<tr>
<td>DaSuppHrlyQty_{a,z,s,h}</td>
<td>MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Quantity per AO per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.6.</td>
</tr>
<tr>
<td>RtRegUp5minQty_{a,z,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Operational Regulation-Up Service Quantity per AO per Settlement Location per Dispatch Interval in the RTBM– The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDn5minQty_{a,z,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Service Quantity per AO per Settlement Location per Dispatch Interval in the RTBM– The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>RtSpin5minQty_{a,z,s,i}</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Quantity per AO per Settlement Location per Dispatch Interval in the RTBM– The value described under Section 4.5.9.6.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>----------</td>
<td>----------</td>
<td>---------------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>RtSupp5minQty&lt;sub&gt;a,z,s,i&lt;/sub&gt;</td>
<td>MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Quantity per AO per Settlement Location per Dispatch Interval in the RTBM– The value described under Section 4.5.9.7.</td>
</tr>
<tr>
<td>DaRegUpMcpHrlyPre&lt;sub&gt;z,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Up Service Market Clearing Price per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.4.</td>
</tr>
<tr>
<td>RtDeSelectRegUp5minFlg&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Deselect Regulation-Up Service Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 whenever an OOME is sent to deselect a Resource for Regulation-Up Service that was cleared in the Day-Ahead Market, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>DaRegDnMcpHrlyPre&lt;sub&gt;z,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Regulation-Down Service Market Clearing Price per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.5.</td>
</tr>
<tr>
<td>RtDeSelectRegDn5minFlg&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Deselect Regulation-Down Service Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 whenever an OOME is sent to deselect a Resource for Regulation-Down Service that was cleared in the Day-Ahead Market, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>DaSpinMcpHrlyPre&lt;sub&gt;z,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Spinning Reserve Market Clearing Price per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.6.</td>
</tr>
<tr>
<td>RtDeSelectSpin5minFlg&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Deselect Spinning Reserve Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 whenever an OOME is sent to deselect a Resource for Spinning Reserve that was cleared in the Day-Ahead Market, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>DaSuppMcpHrlyPre&lt;sub&gt;z,h&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Hour</td>
<td>Day-Ahead Supplemental Reserve Market Clearing Price per Settlement Location per Hour in the DA Market– The value described under Section 4.5.8.7.</td>
</tr>
<tr>
<td>RtDeSelectSupp5minFlg&lt;sub&gt;a,s,i&lt;/sub&gt;</td>
<td>None</td>
<td>Dispatch Interval</td>
<td>Real-Time Deselect Supplemental Reverse Flag per AO per Settlement Location per Dispatch Interval – A flag that is set equal to 1 whenever an OOME is sent to deselect a Resource for Supplemental Reserve that was cleared in the Day-Ahead Market, otherwise, this flag is set equal to zero.</td>
</tr>
<tr>
<td>RtRegUpMcp5minPre&lt;sub&gt;z,i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Up Service Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM– The value described under Section 4.5.9.4.</td>
</tr>
<tr>
<td>RtRegDnMcp5minPre&lt;sub&gt;z,i&lt;/sub&gt;</td>
<td>$/MW</td>
<td>Dispatch Interval</td>
<td>Real-Time Regulation-Down Service Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM– The value described under Section 4.5.9.5.</td>
</tr>
<tr>
<td>Variable</td>
<td>Unit</td>
<td>Settlement Interval</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------------------------</td>
<td>---------</td>
<td>---------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>$RtSpinMcp5minPrc_{z,i}$</td>
<td>$$/MW$</td>
<td>Dispatch Interval</td>
<td>Real-Time Spinning Reserve Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM – The value described under Section 4.5.9.6.</td>
</tr>
<tr>
<td>$RtSuppMcp5minPrc_{z,i}$</td>
<td>$$/MW$</td>
<td>Dispatch Interval</td>
<td>Real-Time Supplemental Reserve Market Clearing Price per Settlement Location per Dispatch Interval in the RTBM – The value described under Section 4.5.9.7.</td>
</tr>
<tr>
<td>$RtOomHrlyAmt_{a,s,h}$</td>
<td>$</td>
<td>Hour</td>
<td>Real-Time Out-Of-Merit Make Whole Payment Amount per AO per Settlement Location per Hour - The amount to AO $a$ for eligible Resource Settlement Location $s$ in Hour $h$ for Out-of-Merit Energy and Operating Reserve resulting from an OOME.</td>
</tr>
<tr>
<td>$RtOomDlyAmt_{a,s,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make Whole Payment Amount per AO per Settlement Location per Operating Day - The amount to AO $a$ for eligible Resource Settlement Location $s$ in Operating Day $d$ for Out-of-Merit Energy and Operating Reserve resulting from an OOME.</td>
</tr>
<tr>
<td>$RtOomAoAmt_{a,m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make Whole Payment Amount per AO per Operating Day - The amount to AO $a$ associated with Market Participant $m$ in Operating Day $d$ for Out-of-Merit Energy and Operating Reserve resulting from an OOME.</td>
</tr>
<tr>
<td>$RtOomMpAmt_{m,d}$</td>
<td>$</td>
<td>Operating Day</td>
<td>Real-Time Out-Of-Merit Make Whole Payment Amount per MP per Operating Day - The amount to MP $m$ in Operating Day $d$ for Out-of-Merit Energy and Operating Reserve resulting from an OOME.</td>
</tr>
<tr>
<td>$EqrRtOom5minPrc_{a,s,i}$</td>
<td>$</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting Out-of-Merit Make Whole Payment Amount per AO per Settlement Location per Dispatch Interval - The Out-of-Merit make-whole amount to AO $a$ for Dispatch Interval $i$ at Resource Settlement Location $s$ for use by AO $a$ in reporting such Make Whole Payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
<tr>
<td>$EqrRtOom5minQty_{a,s,i}$</td>
<td>MWh</td>
<td>Dispatch Interval</td>
<td>Real-Time Electric Quarterly Reporting Out-of-Merit Make Whole Payment Quantity per AO per Settlement Location per Dispatch Interval – This value is set equal to 1 if $EqrRtOom5minPrc_{a,s,i}$ &gt; 0 for use by AO $a$ in reporting such Make Whole Payments to FERC in accordance with FERC EQR requirements.</td>
</tr>
</tbody>
</table>

$a$ none none An Asset Owner.
$s$ none none A Settlement Location.
$i$ none none A Dispatch Interval.
$h$ none none An Hour.
$d$ none none An Operating Day.
$m$ none none A Market Participant.
<table>
<thead>
<tr>
<th>Variable</th>
<th>Unit</th>
<th>Settlement Interval</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t$</td>
<td>none</td>
<td>none</td>
<td>A single tagged Interchange Transaction, virtual energy transaction, Bilateral Settlement Schedule, contracted Operating Reserve transaction, TCR instrument, ARR award, Reserve Sharing Event, Start-Up Event or Transition Event identifier.</td>
</tr>
</tbody>
</table>

**SPP Tariff (OATT)**

**Attachment AE**

### 6.2.4 Out-of-Merit Energy Dispatch

The Transmission Provider may issue an OOME to any Resource not on outage. The Transmission Provider will make every effort to define and activate the appropriate constraints in RTBM SCED within one (1) hour of the time the OOME is issued.

A local transmission operator may 1) request the Transmission Provider to issue an OOME or 2) issue an OOME directly to the Resource(s) and will notify the Transmission Provider that it has done so. If the local transmission operator determines there is an adequate amount of time prior to issuing the OOME directly to the Resource, the local transmission operator will coordinate with the Transmission Provider to ensure the OOME is provided by the Transmission Provider. If the initial OOME is issued by the local transmission operator, the local transmission operator shall coordinate with the Transmission Provider to ensure subsequent OOMEs are provided by the Transmission Provider.

During the period of time an OOME is imposed, the Transmission Provider will take the following actions:

1. The Transmission Provider will issue an OOME at either the fixed MW level or an OOME cap and/or OOME floor MW level the Resource is expected to produce until such time as the constraint can be resolved by SCED through the RTBM.
2. For the current dispatch interval and all future dispatch intervals during the period of time an OOME is imposed, a Resource will receive Setpoint Instructions that are adjusted as specified in the Market Protocols.
3. The Transmission Provider will notify the Market Participant when the OOME event ends.
(4) To the extent that the OOME was initiated directly by a local transmission operator, such OOME may also specify either the fixed MW level or an OOME cap and/or OOME floor MW level. Market Participants shall be compensated for such OOME in accordance with Section 8.6.6 of this Attachment AE as if they had been issued an OOME by the Transmission Provider; except that if the Market Monitor determines that the Resource selected pursuant to Section 6.2.4(4) of this Attachment AE was selected by the local transmission operator in a discriminatory manner and the Resource was affiliated with the local transmission operator, such Resource shall not be eligible for compensation under Section 8.6.6 of this Attachment AE. Such determination shall be made using the same standards and procedures prescribed for Resource selection in the Intra-Day Reliability Unit Commitment process, as set forth in Section 6.1.2.1 of this Attachment AE. The recovery of the compensation paid by the Transmission Provider shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(5) To the extent that the OOME was initiated by the Transmission Provider at the request of a local transmission operator, such Resources issued OOMEs shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. In such event, Market Participants shall be compensated for such OOMEs in accordance with Section 8.6.6 of this Attachment AE. The recovery of the compensation paid by the Transmission Provider shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(6) To the extent that the OOME was initiated by the Transmission Provider, such Resources issued an OOME shall be selected by the Transmission Provider in a non-discriminatory manner, which will be verified by the Market Monitor through the process described under Section 6.1.2.1 of this Attachment AE. Recovery of compensation for Resources directly issued OOMEs by Transmission Provider that are received under Section 8.6.6 of this Attachment AE shall be collected regionally under Section 8.8 of this Attachment AE.

(7) The Transmission Provider, local transmission operator, and affected Resource owners shall develop operating guides to be applied to OOMEs made to relieve known and recurring reliability issues or to relieve known and recurring Emergency Conditions. Such Resources will be compensated in the same manner as any other Resource that is issued OOMEs. The recovery of the compensation paid by the Transmission Provider under
Section 8.6.6 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

In addition to the actions listed above, if an OOME is issued in response to an Emergency Condition, the Transmission Provider will post the Emergency Condition on OASIS as soon as possible. The Transmission Provider shall displace the OOME with a market solution as soon as possible consistent with system safety and reliability.

8.6.6 Real-Time Out-of-Merit Amount

An RTBM OOME payment will be made for each Asset Owner with a Resource that passes a primary Contingency Reserve deployment test as described in Section 2.10.1 of this Attachment AE and/or receives an OOME from the Transmission Provider or local transmission operator that creates a cost to the Asset Owner or that adversely impacts the Asset Owner’s Day-Ahead Market position for Energy and/or Operating Reserve. Resources issued an OOME by the Transmission Provider or a local transmission operator that the Market Monitor determines were selected in a discriminatory manner, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the issuing party are not eligible to receive a RTBM OOME payment. RTBM OOME payments made to Asset Owners that received an OOME to address a Local Reliability Issue including Local Emergency Condition shall be recovered locally as described under Section 8.6.7(B). RTBM OOME payments made to Asset Owners that received an OOME to address a reliability issue other than a Local Reliability Issue shall be recovered regionally under Section 8.8. The amount will be calculated on a Dispatch Interval basis as follows:

1. If the OOME is for Energy in the up direction and the Energy Offer Curve cost associated with the Resource’s additional output attributable to its response (“OOME MW”) floor or fixed is greater than the RTBM LMP, the Asset Owner will receive a payment for the difference multiplied by the OOME floor or fixed MW. The payment shall be limited to the amount necessary to compensate the Asset Owner for any under-recovery resulting from its Resource’s response to the OOME. The OOME MW is calculated as the positive difference between (i) the lesser of the actual Resource output or the Resource’s OOME floor or fixed MW and (ii) the Resource’s economic operating point. The Resource’s
economic operating point is calculated as described under Section 8.6.5(4)(d) of this Attachment AE;

(2) If the OOME is for Energy in the down direction (including a Resource de-commitment or movement of an MCR to a configuration with a lower applicable maximum capacity operating limit) and the RTBM LMP is greater than the Day-Ahead Market LMP, the Asset Owner will receive a payment equal to the difference multiplied by the Resource’s reduction in output attributable to its response (“OOME MW”) cap or fixed. The payment shall be limited to the amount necessary to compensate the Asset Owner for any increase in net settlement costs resulting from its response to the OOME. The OOME MW is calculated as the maximum of zero (0) or the difference between the Resource’s Day-Ahead Market cleared Energy MW and the greater of (i) actual Resource output or (ii) the Resource’s OOME cap or fixed MW;

(3) If an OOME (including a Resource de-commitment instruction or movement of an MCR to a configuration with a lower applicable maximum capacity operating limit) causes the RTBM cleared amount of an Operating Reserve product to be less than the Day-Ahead Market cleared amount of the corresponding Operating Reserve product and the RTBM MCP is greater than the Day-Ahead Market MCP, the Asset Owner will receive a payment for the difference multiplied by the OOME Operating Reserve MW. The OOME Operating Reserve MW is calculated as the maximum of zero (0) or the difference between the Resource’s Day-Ahead Market cleared Operating Reserve MW and the Resource’s RTBM cleared Operating Reserve MW.

(4) To the extent that additional costs are incurred as a direct result of an OOME that are not addressed through the compensation mechanisms described in (1) through (3) above, Asset Owners may request additional compensation through submittal of actual cost documentation to the Transmission Provider. The Transmission Provider will review the submitted documentation and confirm that the submitted information is sufficient to document actual costs and that all or a portion of the actual costs are eligible for recovery.
## EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION

### OBJECTIVE OF REVISION

**Objectives of Revision Request:**

*Describe the problem/issue this revision request will resolve.*

The GI request queue is overwhelmed with more requests than can be accommodated within required tariff timeline using current resources and procedures. A significant amount of time and resources are dedicated to producing the “Stand-Alone Scenario” provided as part of the DISIS evaluation.

*Describe the benefits that will be realized from this revision.*

By eliminating the “Stand-Alone Scenario”, which considers each Interconnection Request by itself, from the DISIS process, a significant amount of work will be eliminated which will free SPP’s resources to focus on the cluster study results which are the binding results, which will permit study results to be available earlier than they currently are. To compensate for the elimination of this provision, SPP will make the stand alone equivalent study models available earlier in the study process to customers or their agents through the existing confidentiality provisions so that they may conduct a “stand-alone scenario” of their own, if desired. The model timing is not defined in the tariff, but will be incorporated into internal study procedures.

This is purely an internal process change that will result in the elimination of the stand-alone scenario such that it will no longer be included in study reports. There is no need for an impact analysis.

### SPP STAFF ASSESSMENT

SPP staff supports this revision request.

### IMPACT

**Will the revision result in system changes?**

- [ ] No
- [x] Yes

**Summarize changes:**

- [ ]

**Will the revision result in process changes?**

- [ ] No
- [x] Yes

**Summarize changes:**

- [ ]

**Is an Impact Assessment required?**

- [x] No
- [ ] Yes

If no, explain:

**Estimated Cost:** $

**Estimated Duration:** months

**Primary Working Group Score/Priority:**
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<th>SPP DOCUMENTS IMPACTED</th>
<th>Protocol Section(s):</th>
<th>Protocol Version:</th>
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<td>Revision Request Process</td>
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<td>SPP Communications Protocols</td>
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WORKING GROUP REVIEWS AND RECOMMENDATIONS
List Primary and any Secondary/Impacted WG Recommendations as appropriate

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<thead>
<tr>
<th>Primary Working Group: RTWG</th>
<th>Date: 2/22/2018</th>
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<tr>
<td>Abstained: None</td>
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<td>Opposed: None</td>
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Reason for Opposition:

| Secondary Working Group: |
| Date: |
| Action Taken: |
| Abstained: |
| Opposed: |

Reasons for Opposition:

| Secondary Working Group: |
| Date: |
| Action Taken: |
| Abstained: |
| Opposed: |

Reasons for Opposition:

| Secondary Working Group: |
| Date: |
| Action Taken: |
| Abstained: |
| Opposed: |

Reasons for Opposition:
8.4 Scope of Definitive Interconnection System Impact Study.

The Interconnection System Impact Study shall evaluate the impact of the proposed interconnection on the reliability of the Transmission System. The Interconnection System Impact Study will consider two different scenarios as described below.

8.4.1 The “Cluster Scenario”Interconnection System Impact Study will consider the Base Case, as well as all Interconnection Requests in the Definitive Interconnection System Impact Study Queue and all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Definitive Interconnection System Impact Study is commenced:
(i) are directly interconnected to the Transmission System;

(ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request;

(iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and

(iv) have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

8.4.2 The “Stand Alone Scenario” will consider the Base Case as well as all generating facilities (and with respect to (iii) below, any identified Network Upgrades associated with such higher queued interconnection) that, on the date the Definitive Interconnection System Impact Study is commenced:

(i) are directly interconnected to the Transmission System;

(ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request;

(iii) have a pending higher queued Interconnection Request to interconnect to the Transmission System; and

(iv) have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

The Definitive Interconnection System Impact Study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The Definitive Interconnection System Impact Study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The Definitive Interconnection System Impact Study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of cost responsibility and a non-binding good faith estimated time to construct.

8.4.3 Availability of Limited Operation.

If the Definitive Interconnection System Impact Study “Stand Alone Scenario” as defined in Section 8.4.2 determines that the full amount of interconnection capacity requested by the Interconnection Customer is not available by its requested Commercial Operation Date due to transmission constraints that may be remedied by an upgrade(s) with an in-service date beyond the Commercial Operation Date proposed by the Interconnection Customer, the Transmission Provider shall quantify the amount of interconnection capacity available to the Interconnection Customer prior to
the in-service date of such upgrade(s) (“Limited Operation”). The Interconnection Customer shall be notified of the amount of interconnection capacity available under the Limited Operation condition. The Interconnection Customer may choose to proceed with Limited Operation by executing the Limited Operation Interconnection Facilities Study Agreement in Appendix 4A. The Interconnection Customer may also be subject to conditions in Section 8.7 of the GIP.

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