Southwest Power Pool
REGIONAL TARIFF WORKING GROUP MEETING
September 27, 2018
Renaissance Tower – Dallas, Texas

• Summary of Motions and Action Items •

**Agenda Item 3 – Consent Agenda**—Motion by Tom Hestermann (Sunflower) seconded by Jim Bixby (ITC) to approve the consent agenda. The motion passed unanimously.

**Agenda Item 8 – RR 322 – AFC Load Forecast Inputs**—Motion by Tom Hestermann (Sunflower) seconded by Steve Sanders (WAPA) to approve RR 322. The motion passed with two abstaining (AEP, Evergy).

**Agenda Item 9 – RR 318 – Contingency Reserve Requirement Calculation Change**—Motion by Tom Hestermann (Sunflower) seconded by Bernie Liu (Xcel) to approve RR 318. The motion passed unanimously.

**Agenda Item 10 – RR 319 – MIS over Miles City DC Tie**—Motion by Mo Awad (Evergy) seconded by Jessica Meyer (LES) to approve RR 319. The motion passed unanimously.

**Agenda Item 11a – RR 288 – DVER Dispatch Instruction Rules Clean-up**—Motion by Mo Awad (Evergy) seconded by Bernie Liu (Xcel) to approve RR 288. The motion passed unanimously.

**Agenda Item 11b – RR 316 – MCR Plant and Group Min Down Time Parameter Addition**—Motion by John Varnell (Tenaska) seconded by Tom Hestermann (Sunflower) to approve RR 316. The motion passed unanimously.

**Agenda Item 14 – RR 323 – Order 841 Compliance**—Motion by Tom Hestermann (Sunflower) seconded by Rob Janssen (Dogwood) that the RTWG has reviewed RR 323 and believes the Tariff revisions implement the market protocols as presented. The RTWG recommends that the revisions made to Section 28.6 of the Tariff to be included in RR 323. The motion passed with five abstaining (AECC, Evergy, KMEA, MJMEUC, Tenaska, Xcel).
Minutes No. [2018 09 27]

Southwest Power Pool
REGIONAL TARIFF WORKING GROUP MEETING
September 27, 2018
Renaissance Tower – Dallas, Texas

• M I N U T E S •

Agenda Item 1 – Administrative Items
SPP Chair David Kays (OGE) called the meeting to order at 8.32 a.m. The following members were in attendance or represented by proxy:

David Kays Oklahoma Gas & Electric Company
Robert Pick Nebraska Public Power District
Mo Awad KCP&L and Westar, Evergy Companies
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
Terri Gallup American Electric Power
Greg Garst Omaha Public Power District
Joel Hendrickson Tri-State Generation and Transmission
Tom Hestermann Sunflower Electric Power Corporation
Rob Janssen Dogwood Energy, LLC
Bernie Liu Xcel Energy
Brandon McCracken Western Farmers Electric Cooperative
Jessica Meyer Lincoln Electric System
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
Todd Tarter Empire District Electric Company
John Varnell Tenaska Power Services Company

The following proxies were recorded:
JP Maddock (BEPC) for Tom Christensen (BEPC)
Heather Starnes (MJMEUC) for Neil Rowland (KMEA)

(Attachment 1a – 2018 09 27 RTWG In Person Attendance)
(Attachment 1b – 2018 09 27 RTWG WebEx Attendance)

Agenda Item 2 – Review of Past Action Items
Nicole Wagner (SPP) stated that the presentation for Action Item 87 will be given at the RTWG October 25, 2018 meeting. Action Item 88 will be closed with resettlement information being provided as part of the monthly Settlements Update.
Agenda Item 3 – Consent Agenda (Approval Item)
David Kays (OGE) presented the consent agenda, which consisted of the minutes from the August and September meetings, and one market revision request. Motion by Tom Hestermann (Sunflower) seconded by Jim Bixby (ITC) to approve the consent agenda. The motion passed unanimously.

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. October 2018 will likely have Z2 updates.

Agenda Item 6 – Settlements Update
Steve Davis (SPP) provided an update on the tax waiver changes resettlement. Resettlement for December 2017 and January 2018 occurred in September 2018. Nicole Wagner (SPP) informed the group that for all future updates to the Settlement Replacement Project, please contact your CWG representative or Dana Boyer (SPP).

Agenda Item 7 – Legal Update
Joe Ghormley (SPP) provided the legal update using the September 2018 Regulatory Status Report and Regulatory Outlook as the baseline (http://www.spp.org/spp-documents-filings/?id=18504). A brief overview of each filing made since the latest publication was given, as well as an overview of upcoming filings.

Agenda Item 8 – RR 322 – AFC Load Forecast Inputs (Approval Item)
Gerardo Ugalde (SPP) introduced a revision request to update the data utilized for the monthly forecast. If additional load forecast data is available, it will be used in place of the historical data that is being used. If the SDX data is unavailable, the monthly load forecast data derived from historical actuals can be used as a substitute. Motion by Tom Hestermann (Sunflower) seconded by Steve Sanders (WAPA) to approve RR 322. The motion passed with two abstaining (AEP, Evergy). (Attachment 2 – RR 322 Recommendation Report)

Agenda Item 9 – RR 318 – Contingency Reserve Requirement Calculation Change (Approval Item)
Garrett Crowson (SPP) presented a revision request to modify the Contingency Reserve (CR) requirement calculation from a daily amount to an hourly amount. This change will increase granularity in the calculation methodology, and allow SPP to more accurately and reliably set the reserve requirement for each hour in the operating day. Motion by Tom Hestermann (Sunflower) seconded by Bernie Liu (Xcel) to approve RR 318. The motion passed unanimously. (Attachment 3 – RR 318 Recommendation Report)

Agenda Item 10 – RR 319 – MIS over Miles City DC Tie (Approval Item)
Ken Quimby (SPP) began by explaining that the current language in Business Practice 5500 exempts the Miles City DC Tie from Market Import Service. This revision request proposes to remove the exemption from Market Import Service and standardize the service over all SPP ties. Motion by Mo Awad (Evergy)
seconded by Jessica Meyer (LES) to approve RR 319. The motion passed unanimously.  
(Attachment 4 – RR 319 Recommendation Report)

**Agenda Item 11 – Market Revision Requests**

- **RR 288 – DVER Dispatch Instruction Rules Clean-up (Approval Item)**
  Kristen Darden (SPP) introduced a revision request to remove barriers to Dispatchable Variable Energy Resources utilizing control statuses and to clean-up sections stating control status is ignored or not allowed for DVERs.  **Motion by Mo Awad (Evergy) seconded by Bernie Liu (Xcel) to approve RR 288. The motion passed unanimously.**  
  (Attachment 5 – RR 288 Recommendation Report)

- **RR 316 – MCR Plant and Group Min Down Time Parameter Addition (Approval Item)**
  Kristen Darden (SPP) introduced a revision request to add two additional commitment parameters for Multi-Configuration Resources to prevent combined cycle resources from being committed and de-committed in a manner that potentially violates physical equipment limitations.  **Motion by John Varnell (Tenaska) seconded by Tom Hestermann (Sunflower) to approve RR 316. The motion passed unanimously.**  
  (Attachment 6 – RR 316 Recommendation Report)

**Agenda Item 12 – Revision Request Process Discussion**

As part of the meeting survey from July 26, 2018, a clarification was requested regarding what procedurally a secondary working group is allowed to do in terms of voting on a revision request that has already been approved by the MOPC.  Aaron Shipley (SPP) facilitated the discussion and indicated that the working group would still review, and potentially modify, the revision request per the process.  Any substantive changes would need to be discussed with the primary working group and could result in the revision request being reviewed by the MOPC at its next meeting.  The topic of presenting at the MOPC was also addressed and while it is generally the chair of the primary working group who presents the revision requests, there is no restriction on having another person represent a particular interest or topic.

**Agenda Item 13 – SPP Stakeholder Prioritization Process**

This item was tabled until the October 25, 2018 meeting.

**Agenda Item 14 – RR 323 – Order 841 Compliance (Approval Item)**

The RTWG reviewed the revision request and suggested modifications.  **Motion by Tom Hestermann (Sunflower) seconded by Rob Janssen (Dogwood) that the RTWG has reviewed RR 323 and believes the Tariff revisions implement the market protocols as presented. The RTWG recommends that the revisions made to Section 28.6 of the Tariff to be included in RR 323. The motion passed with six abstaining (AECC, Evergy, KMEA, MJMEUC, Tenaska, Xcel).**  
(Attachment 7 – RR 323 RTWG Comments 2018 09 27)

**Agenda Item 15 – Working Group Survey**

Chris Cranford (SPP) provided the QR code and link for this month’s survey and it will be included in the recap email that will be sent on Friday.
Agenda Item 16 – Review of Motions, Action Items, and Future Meetings

The next scheduled RTWG meeting is a net conference October 8, 2018 (1:00 p.m. – 4:00 p.m.).

Respectfully Submitted,

Brenda Fricano on behalf of Marisa Choate
Secretary

Attachments
(Attachment 1a – 2018 09 27 RTWG In Person Attendance)
(Attachment 1b – 2018 09 27 RTWG WebEx Attendance)
(Attachment 2 – RR 322 Recommendation Report)
(Attachment 3 – RR 318 Recommendation Report)
(Attachment 4 – RR 319 Recommendation Report)
(Attachment 5 – RR 288 Recommendation Report)
(Attachment 6 – RR 316 Recommendation Report)
(Attachment 7 – RR 323 RTWG Comments 2018 09 27)
## IN PERSON ATTENDANCE LIST

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<tr>
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<tr>
<td>Robert Stillwell</td>
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<td>Rodney Massman</td>
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<td></td>
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<tr>
<td>Steve Davis(SPP)</td>
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Todd Tarter (Liberty-EDE)  ttarter@empiredistrict.com
Tom Christensen  tomc@bepc.com
Walt Cecil  walt.cecil@psc.mo.gov
Revision Request Recommendation Report

<table>
<thead>
<tr>
<th>RR #: 322</th>
<th>Date: 10/1/2018</th>
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<tr>
<td>RR Title: AFC Load Forecast Inputs</td>
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**SUBMITTER INFORMATION**

<table>
<thead>
<tr>
<th>Name: Gerardo Ugalde</th>
<th>Company: SPP</th>
</tr>
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<tbody>
<tr>
<td>Email: <a href="mailto:gugalde@spp.org">gugalde@spp.org</a></td>
<td>Phone: 501-614-3212</td>
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**EXECUTIVE SUMMARY AND RECOMMENDATION FOR MOPC AND BOD ACTION**

**OBJECTIVE OF REVISION**

Objectives of Revision Request:
Attachment C, Section 4.3.2 specifies that SPP utilize monthly forecast data from the EIA411 annual report for calculating AFC and for any balancing authorities not included in the EIA411 annual report, SPP will use the data available through SDX. In early 2018, while reviewing internal processes, SPP staff determined that for the monthly forecast SPP was utilizing historical data, derived monthly load forecast values, rather than the data from the EIA411 or SDX data. Upon further review, SPP determined that the EIA411 data could not be utilized for the monthly forecast because the data is at the SPP balancing authority level, rather than the local balancing authority level needed for the AFC calculations. As a result, on January 30, 2018, SPP updated its process with the forecast data that is available through SDX, as provided by Attachment AC, Section 4.3.2.

SPP staff took an action item to review the load forecast process used in the AFC calculations. SPP found that there is more weather based load forecast data that can be used in the AFC process. SPP also determined that in case that SDX data is unavailable, that monthly load forecast data derived from historical actuals can be used as a substitute. As a result, Section 4.1.2, 4.2.2, 4.3.2 and 8 were changed to reflect these changes.

**SPP STAFF ASSESSMENT**

SPP supports this revision request.

**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: Changes in this RR are language only changes with no systems being impacted, therefore no Impact Assessment is required.

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

<table>
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<tr>
<th>SPP DOCUMENTS IMPACTED</th>
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<tr>
<td>☐ Market Protocols</td>
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<td>Criteria</td>
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<tr>
<td>Tariff</td>
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<td>Business Practice</td>
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<td>Integrated Planning Model (ITP Manual)</td>
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<td>Reliability Coordinator and Balancing Authority Data Specifications (RDS)</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

**Primary Working Group: RTWG**
- **Date:** 9/27/2018
- **Action Taken:** To approve RR 322
- **Abstained:** AEP, Evergy
- **Opposed:** None

**Reason for Opposition:**

**Secondary Working Group: TWG**
- **Date:**
- **Action Taken:**
- **Abstained:**
- **Opposed:**

**Reason for Opposition:**

**Secondary Working Group: RCWG**
- **Date:**
- **Action Taken:**
- **Abstained:**
- **Opposed:**

**Reason for Opposition:**

**MOPC**
- **Date:**
- **Action Taken:**
- **Abstained:**
- **Opposed:**

**Reasons for Opposition:**

**BOD/Member Committee**
- **Date:**
- **Action Taken:**
- **Abstained:**
- **Opposed:**
4.1.2 Load Forecast

The hourly load forecast data (for day 1 – day 7) is created by the Transmission Provider for the State Estimator model from the short-term and mid-term load forecast tools that use weather data from weather stations spread over the Transmission System and historical actual load data received from Balancing Authorities within the SPP Reliability Coordination Area. The Transmission Provider also includes load forecast data from neighboring Reliability Coordinators that is available through SDX. The Transmission Provider derives load forecast data for day 8 – day 31 from the data of day 1 – day 7 by applying a factor that represents an historical increase or decrease of load on weekly basis during the year. If additional weather based load forecast data is available that extends past day 7, that weather based load forecast data will be used instead of the load forecast data that was derived from day 1 – day 7.

4.2.2 Load Forecast

The hourly load forecast data (for day 1 – day 7) is created by the Transmission Provider for the State Estimator from the short-term and mid-term load forecast tools that use weather data from weather stations spread over the Transmission System and historical actual load data received from Transmission Operators within the SPP Reliability Coordination Area. The Transmission Provider also includes load forecast data from neighboring Reliability Coordinators that is available through SDX. The Transmission Provider derives load forecast data for day 8 – day 31 from the data of day 1 – day 7 by applying a factor that represents an historical increase or decrease of load on weekly basis during the year. If additional weather based load forecast data is available that extends past day 7.
that weather based load forecast data will be used instead of the load forecast data that was derived from day 1 – day 7.

4.3.2 Load Forecast

The Transmission Provider utilizes monthly forecast data from the EIA411 annual report. For Balancing Authority Areas not included in the EIA411 annual report, the Transmission Provider uses forecast data that is available through SDX. If SDX data is unavailable, the Transmission Provider will derive a monthly load forecast value by applying a factor based on observed monthly historical increases or decreases of load.
8. AFC Flowchart

Process Flow diagram Operating, Planning, and Study Horizons

**Topology**
- State Estimator Models
- Updated with outages.

**Outage data from SDX**

**Short and mid-term load forecast (Operating and Planning Horizons)**
- Load forecast data from EIA411 – *annual report* (Study Horizon)

**ExternalSchedules.txt**
- (Operating Horizon): File that has Reservation numbers of scheduled Transmission Service Requests

**ucfile.csv:** Unit commitment data file

**Transmission Service Requests**
- OASIS plus
- ExternalReservations.csv

**Powerflow**
- AC Power flow

**Operating Horizon:**
- Day 1, Day 1, after 10:00 a.m.
- Updated at least once/day

**Planning Horizon:**
- Day after Operating thru day 31
- Updated at least once/day

**Study Horizon:**
- 12 values (Month 2, 13)
- *Updated at least once/month*

**Calculates:**
- Base flows of flow gates
- DF of paths

**Base flows**
- DF values

**AtcDataSourceRFCalcGSF.csv**
- (Operating and Planning Horizons)MonthAtcDataSourceRFCalcGSF.csv (Study Horizon)

**Base flows**
- DF values
- TFC values

**webTrans**
- Calculates:
  - AFC of all flow gates
  - ATC of all paths
Topology
State Estimator Models
Updated with outages.

Outage data from SDX

Short and mid-term load forecast (Operating and Planning Horizons)
Load forecast data from SDX (Study Horizon)

ExternalSchedules.txt
(Operating Horizon): File that has Reservation numbers of scheduled Transmission Service Requests

ucfile.csv: Unit commitment data file

Transmission Service Requests
OASIS plus
ExternalReservations.csv

Powerflow
AC Power flow

Operating Horizon:
• Day1. Day1&2 after 10:00 a.m
• Updated at least once/day

Planning Horizon:
• Day after Operating thru day 31
• Updated at least once/day

Study Horizon:
• 12 values (Month 2, 13)
• Updated at least once/month

Calculates:
• Base flows of flow gates
• DF of paths

Base flows
DF values

AtcDataSourceRFCalcGSF.csv
(Operating and Planning Horizons)MonthAtcDataSourceRFCalcGSF.csv (Study Horizon)

Base flows
DF values
TFC values

webTrans Calculates:
• AFC of all flow gates
• ATC of all paths

Transmission Service Requests
Revision Request Recommendation Report

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**RR Title:** Contingency Reserve Requirement Calculation Change

**SUBMITTER INFORMATION**

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<tr>
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<tbody>
<tr>
<td>Submitter Name:</td>
<td>Garrett Crowson</td>
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<tr>
<td>Company:</td>
<td>Southwest Power Pool</td>
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<tr>
<td>Email:</td>
<td><a href="mailto:gcrowson@spp.org">gcrowson@spp.org</a></td>
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<tr>
<td>Phone:</td>
<td>501-688-8237</td>
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**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 SPP RSG Operating process’s current definition, and subsequently SPP’s calculation, of Minimum Daily Contingency Reserve Requirement is not written to use the Most Severe Single Contingency as the basis for the calculation. The current language requirement is targeted towards single largest and next largest capacities of the generating units. Also, the requirement is set off such capacities as a daily amount, which may not accurately represent the amount needed for covering the Most Severe Single Contingency hour to hour. Lastly, would like to approve upon the extra capacity over MSSC, which could now be seen as half of the second largest unit’s capacity.

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

The revision allows SPP to use the Most Severe Single Contingency as the basis of the Minimum Contingency Reserve Requirement and also do so on an hourly basis. The revision also allows SPP to more accurately set the extra capacity needed above the MSSC to ensure recovery and met NERC Standards. By doing the above this allows SPP to more accurately and reliable set the reserve requirement for each hour in the operating day.

**SPP STAFF ASSESSMENT**

SPP staff initiated and supports revision request

**IMPACT**

Will the revision result in system changes? ☑ Yes

Summarize changes:

Will the revision result in process changes? ☑ Yes

Summarize changes:

Is an Impact Assessment required? ☑ Yes

If no, explain:

Estimated Cost: $  
Estimated Duration: months

Primary Working Group Score/Priority:

**SPP DOCUMENTS IMPACTED**
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<th>Protocol Version: 59a</th>
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### WORKING GROUP REVIEWS AND RECOMMENDATIONS
List Primary and any Secondary/Impacted WG Recommendations as appropriate

| Primary Working Group: ORWG | Date: 09/06/2018 | Action Taken: Unanimously Approved |
| Secondary Working Group: MWG | Date: 09/11/2018 | Action Taken: Unanimously Approved |
| Secondary Working Group: RCWG | Date: 09/20/2018 | Action Taken: Unanimously Approved |
| Secondary Working Group: RTWG | Date: 9/27/2018 | Action Taken: Unanimously Approved |
| MOPC | Date: | Action Taken: |
| Abstained: | 
| Opposed: |

### Reasons for Opposition:

| BOD/Member Committee | Date: | Action Taken: |
| Abstained: | 
| Opposed: |

### Reasons for Opposition:

### COMMENTS

| Comment Author: |
| Date Comments Submitted: |
Market Protocols

1. Glossary

Most Severe Single Contingency

As defined in Attachment AE of the Tariff.

4.1.5.2 Operating Reserve Scarcity Factors

SPP calculates and posts Contingency Reserve, Regulation-Up and Regulation-Down Scarcity Factors as described below.

1. The Contingency Reserve Scarcity Factor varies based on the MW amount of Contingency Reserve Shortage. The Contingency Reserve shortage MW values that result in changes to the scarcity price values are calculated by SPP based on the projected Resource availability available capacity Most Severe Single Contingency (MSSC) in the SPP BAA for the Operating Day in accordance with the following rules:

(a) For Contingency Reserve Shortages less than or equal to one-fourth half of the SPP BAA’s Reserve Sharing Group Contingency Reserve requirement second largest projected Resource Maximum Normal Capacity Operating Limit the Contingency Reserve Scarcity Factor will be set to 0.25.

(b) For Contingency Reserve Shortages greater than one-fourth half the SPP BAA’s Reserve Sharing Group Contingency Reserve requirement above SPP BAA’s Reserve Sharing group portion of the MSSC but less than or equal to the SPP BAA’s Reserve Sharing Group Contingency Reserve requirement above SPP BAA’s Reserve Sharing group portion of the MSSC the Contingency Reserve Scarcity Factor will be set to 0.25.

The Contingency Reserve Scarcity Factor varies based on the MW amount of Contingency Reserve Shortage. The Contingency Reserve shortage MW values that result in changes to the scarcity price values are calculated by SPP based on the projected Resource availability available capacity Most Severe Single Contingency (MSSC) in the SPP BAA for the Operating Day in accordance with the following rules:

(a) For Contingency Reserve Shortages less than or equal to one-fourth half of the SPP BAA’s Reserve Sharing Group Contingency Reserve requirement second largest projected Resource Maximum Normal Capacity Operating Limit the Contingency Reserve Scarcity Factor will be set to 0.25.

(b) For Contingency Reserve Shortages greater than one-fourth half the SPP BAA’s Reserve Sharing Group Contingency Reserve requirement above SPP BAA’s Reserve Sharing group portion of the MSSC but less than or equal to the SPP BAA’s Reserve Sharing Group Contingency Reserve requirement above SPP BAA’s Reserve Sharing group portion of the MSSC the Contingency Reserve Scarcity Factor will be set to 0.25.
Maximum Normal Capacity Operating Limit, the Contingency Reserve Scarcity Factor will be set to 0.5.

(c) For Contingency Reserve Shortages greater than the SPP BAA’s Reserve Sharing Group Contingency Reserve requirement, the Contingency Reserve above SPP BAA’s Reserve Sharing group portion of the MSSC’s one-half the second largest projected Resource Maximum Normal Capacity Operating Limit, the Contingency Reserve Scarcity Factor will be set to 1.

(2) The Regulation-Up Scarcity Factor varies based on the MW amount of Regulation-Up shortage. The Regulation-Up shortage MW values that result in changes to the scarcity price values are calculated by SPP using historical Regulation-Up Deployment data in accordance with the following rules:

(a) For Regulation-Up Reserve shortages less than or equal to 30 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 1.

(b) For Regulation-Up Reserve shortages greater than 30 percent but less than or equal to 50 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 2.

(c) For Regulation-Up Reserve shortages greater than 50 percent but less than or equal to 70 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 3.

(d) For Regulation-Up Reserve shortages greater than 70 percent but less than or equal to 80 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 4.

(e) For Regulation-Up Reserve shortages greater than 80 percent but less than or equal to 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 5.

(f) For Regulation-Up Reserve shortages greater than 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Pricing level will be set to the maximum scarcity pricing level described in Section 4.1.5(1)(b).

(3) The Regulation-Down Scarcity Factor varies based on the MW amount of Regulation-Down shortage. The Regulation-Down shortage MW values that result in changes to the scarcity price values are calculated by SPP using historical Regulation-Down Deployment data in accordance with the following rules:

(a) For Regulation-Down Reserve shortages less than 30 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 1.
(b) For Regulation-Down Reserve shortages greater than 30 but less than or equal to 50 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 2.

(c) For Regulation-Down Reserve shortages greater than 50 but less than or equal to 70 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 3.

(d) For Regulation-Down Reserve shortages greater than 70 but less than or equal to 80 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 4.

(e) For Regulation-Down Reserve shortages greater than 80 but less than or equal to 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 5.

(f) For Regulation-Down Reserve shortages greater than 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Pricing level will be set to the maximum scarcity pricing level described in sections 4.1.5(1)(c).

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SPP Tariff (OATT)

Tariff - Attachment AE

1.1 Definitions M

**Most Severe Single Contingency**

The Balancing Contingency Event, due to a single contingency identified using system models maintained within the Reserve Sharing Group (RSG) or a Balancing Authority’s area that is not part of a Reserve Sharing Group, that would result in the greatest loss (measured in MW) of resource output used by the RSG or a Balancing Authority that is not participating as a member of an RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

**8.3.4.3 Operating Reserve Scarcity Factors**

The Transmission Provider calculates and posts Contingency Reserve Scarcity Factors, Regulation-Up Scarcity Factors and Regulation-Down Scarcity Factors as described below.

(1) The Contingency Reserve Scarcity Factor varies based on the MW amount of Contingency Reserve shortage. The Contingency Reserve shortage MW values that result in changes to the scarcity price values are calculated by the Transmission Provider based on the projected
Resource availability available capacity Most Severe Single Contingency (MSSC) in the Transmission Provider’s Balancing Authority Area for the Operating Day in accordance with the following rules:

a. For Contingency Reserve shortages less than or equal to one-fourth half of SPP BAA’s the second largest projected Resource Maximum Normal Capacity Operating Limit the Contingency the SPP Reserve Sharing Group Contingency Reserve requirement required capacity above SPP BAA’s Reserve Sharing group portion of the MSSC, the Reserve Scarcity Factor will be set to 0.25.

b. For Contingency Reserve Shortages greater than one-fourth half the SPP Reserve Sharing Group SPP BAA’s Contingency Reserve requirement the Contingency Reserve required capacity above SPP BAA’s Reserve Sharing group portion of the MSSC but less than or equal to one-half of the second largest projected Resource Maximum Normal Capacity Operating Limit SPP BAA’s Reserve Sharing Group Contingency Reserve requirement the Contingency Reserve required capacity above SPP BAA’s Reserve Sharing group portion of the MSSC, the Contingency Reserve Scarcity Factor will be set to 0.5.

c. For Contingency Reserve Shortages greater than one-half the second largest projected Resource Maximum Normal Capacity Operating Limit the SPP Reserve Sharing Group Contingency Reserve requirement above SPP BAA’s Contingency Reserve requirement above SPP BAA’s Reserve Sharing group portion of the MSSC, the Contingency Reserve Scarcity Factor will be set to 1.

(2) The Regulation-Up Scarcity Factor varies based on the MW amount of Regulation-Up shortage. The Regulation-Up shortage MW values that result in changes to the Scarcity Price values are calculated by the Transmission Provider using historical Regulation-Up deployment data in accordance with the following rules:

a. For Regulation-Up reserve shortages less than or equal to 30 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 1.
b. For Regulation-Up reserve shortages greater than 30 percent but less than or equal to 50 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 2.

c. For Regulation-Up reserve shortages greater than 50 percent but less than or equal to 70 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 3.

d. For Regulation-Up reserve shortages greater than 70 percent but less than or equal to 80 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 4.

e. For Regulation-Up reserve shortages greater than 80 percent but less than or equal to 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Factor will be set to 5.

f. For Regulation-Up Reserve shortages greater than 90 percent of the Regulation-Up system-wide requirement, the Regulation-Up Scarcity Pricing level will be set to the maximum Scarcity Pricing level described in Section 8.3.4.2(2)(b).

(3) The Regulation-Down Scarcity Factor varies based on the MW amount of Regulation-Down shortage. The Regulation-Down shortage MW values that result in changes to the Scarcity Price values are calculated by the Transmission Provider using historical Regulation-Down deployment data in accordance with the following rules:

a. For Regulation-Down reserve shortages less than 30 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 1.

b. For Regulation-Down reserve shortages greater than 30 but less than or equal to 50 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 2.

c. For Regulation-Down reserve shortages greater than 50 but less than or equal to 70 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 3.
d. For Regulation-Down reserve shortages greater than 70 but less than or equal to 80 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 4.

e. For Regulation-Down reserve shortages greater than 80 but less than or equal to 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Factor will be set to 5.

f. For Regulation-Down reserve shortages greater than 90 percent of the Regulation-Down system-wide requirement, the Regulation-Down Scarcity Pricing level will be set to the maximum Scarcity Pricing level described in Section 8.3.4.2(2)(c) of this Attachment AE.

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**RSG Operating Process (reference in Operating Criteria)**

### 1.4 Minimum Annual-Daily-Hourly Contingency Reserve Requirement

The Operating Reliability Working Group (ORWG) will set the methodology for the calculation of the Minimum Daily-Hourly Contingency Reserve Requirement for the SPP Reserve Sharing Group. The SPP Reserve Sharing Group will maintain a Minimum Daily-Hourly Contingency Reserve, over and above any Regulating Reserves, equal to the hourly Most Severe Single Contingency (MSSC) generating capacity of the largest unit within the metered boundaries of any RSG member Balancing Authority plus one-half of the capacity of the next largest generating unit within the metered boundaries of any RSG member Balancing Authority multiplied by an hourly scaling factor. Generation capacity is considered to be added at the first injection of test power of the generator, regardless of commercial status. The hourly scaling factor is set by SPP Reliability Coordinator to ensure reserves are adequate to meet NERC standards. The minimum scaling factor for each hour, as set by the ORWG, is to be 1.2.

If the SPP Reliability Coordinator foresees an operating condition in which reserves are inadequate to cover the Most Severe Single Contingency (MSSC), the SPP Reliability Coordinator has the authority to increase the total SPP Reserve Sharing Group Minimum Daily-Hourly Contingency Reserve Requirement to the level necessary to cover the MSSC for the duration of the operating condition.

Any increased reserves that are based on non-compliance with the NERC Disturbance Control Standard will raise the total SPP Reserve Sharing Group Minimum Annual-Hourly Contingency Reserve Requirement for the SPP Reserve Sharing Group on a quarterly basis. The Operating Reliability Working Group will determine the method by which the increased reserves will be allocated among the members of the SPP Reserve Sharing Group.

Each day, by 7:006:00 am CPT, the SPP Reliability Coordinator will notify each member Balancing Authority of its Daily Minimum Hourly Contingency Reserve Requirement for each hour of the following operating day.
2.4 Reserve Sharing Group – Operating Criteria

SPP is registered with NERC as a Reserve Sharing Group (RSG). 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. BAs participating in the SPP RSG shall meet the requirements set forth in the *SPP RSGOP*, which can be found on the SPP website.
# Revision Request Recommendation Report

<table>
<thead>
<tr>
<th>RR #: 319</th>
<th>Date: 8/22/2018</th>
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<tbody>
<tr>
<td>RR Title: MIS over Miles City DC Tie</td>
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## Submitter Information

<table>
<thead>
<tr>
<th>Submitter Name: Kass Portra</th>
<th>Company: Western Area Power Administration</th>
</tr>
</thead>
<tbody>
<tr>
<td>Email: <a href="mailto:portra@wapa.gov">portra@wapa.gov</a></td>
<td>Phone:</td>
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## Executive Summary and Recommendation for MOPC and BOD Action

To be completed upon Working Group Approval

## Objective of Revision

**Objectives of Revision Request:**
The current Business Practice as approved in RR250 (BP5500) exempts the Miles City DC Tie from MIS service. WAPA proposes to remove this exemption.

Adding MIS service to the Miles City DC Tie will remove any exemptions from this service and standardize the service over all SPP ties. This proposal submitted by the Miles City HVDC Tie operator, Western Area Power Administration.

## SPP Staff Assessment

SPP staff supports this RR

## Impact

Will the revision result in system changes ☐ No ☒ Yes

Summarize changes: Removal of MIS prohibition from TSR validation over Miles City HVDC Tie

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

Summarize changes: Removal of MIS prohibition from TSR validation over Miles City HVDC Tie

Is an Impact Assessment required? ☒ No ☐ Yes

If no, explain:

Estimated Cost: $  
Estimated Duration: months

Primary Working Group Score/Priority:

## SPP Documents Impacted

<table>
<thead>
<tr>
<th>□ Market Protocols</th>
<th>Protocol Section(s):</th>
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<tbody>
<tr>
<td>□ Operating Criteria</td>
<td>Criteria Section(s):</td>
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<td>□ Planning Criteria</td>
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<td>□ Tariff</td>
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<tr>
<td>☒ Business Practice</td>
<td>Business Practice Number: 5500</td>
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<tr>
<td>Integrated Transmission Planning (ITP) Manual</td>
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<td>Revision Request Process</td>
<td>Section(s):</td>
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<tr>
<td>Minimum Transmission Design Standards for Competitive Upgrades (MTDS)</td>
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<tr>
<td>Reliability Coordinator and Balancing Authority Data Specifications (RDS)</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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Reason for Opposition: No objection to this specific RR, i.e. service over the Miles City HVDC Tie. Objection voiced to the existence of MIS in general

<table>
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<th>Secondary Working Group: ORWG</th>
<th>Date: 9/6/2018</th>
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<th>Date 9/12/2018</th>
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Reasons for Opposition:

**COMMENTS**

Comment Author:
SPP Business Practices

Business Practice

1. Market Import Service is available as a Daily or Hourly product that must be reserved prior to submittal of the Import Interchange Transaction Offer.

2. Market Import Service must be requested on the OASIS for each transaction with the service type “MIS” and is subject to the appropriate timing restrictions outlined in Attachment P of the SPP OATT:
   a. **SPP Hourly MIS requests** - SPP Hourly MIS may be reserved beginning at 12:00 Noon for current day and next day as an Import Interchange Transaction. Next day service will be subject to Simultaneous Submission Window processing (Business Practice 2450).
   
   b. **SPP Daily MIS requests** - SPP Daily MIS may be reserved beginning 2 days prior to no later than 12:00 Noon Day prior. If granted before the close of the Day-Ahead market (Day Prior to OD), Daily MIS transmission service may be used in the Day-Ahead Market as an Import Interchange Transaction.

3. To prevent hoarding, Market Import Service will be recalled if not scheduled within two hours after being **Confirmed** for Day-Ahead Market or 30 minutes after being **Confirmed** for Real-Time Balancing Market.

4. **Market Import Service is not available over the Miles City HVDC Tie.**

4. The LCA on the tag must be “SWPP.”
Revision Request Recommendation Report

RR #: 288

RR Title: DVER Dispatch Instruction Rules Clean-up

Date: 6/12/2018

SUBMITTER INFORMATION

Submitter Name: Erin Cathey

Company: Southwest Power Pool

Email: ecathey@spp.org

Phone: 501.614.3239

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.

RR272 requires NDVERs to convert to DVER registration after a 2 year period following SPP BOD approval. Since approved by the SPP MOPC and SPP BOD July 2018, some DVERs will need to have the ability to operate using the various control statuses, e.g., hydro-electric resources. The purpose of this RR is to remove barriers to DVERs utilizing control statuses, explained in Section 4.4.2.2.3 of the Market Protocols and to clean-up sections stating control status is ignored or not allowed for DVERs.

Describe the benefits that will be realized from this revision.

DVERs will have the ability to utilize control statuses as appropriate and dispatch instructions will be calculated accordingly.

SPP STAFF ASSESSMENT

SPP staff supports this Revision Request.

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:

Estimated Cost: $47,280

Estimated Duration: 4 months

Primary Working Group Score/Priority: Medium

SPP DOCUMENTS IMPACTED

☑ Market Protocols

Protocol Section(s): Glossary D, R, 4.2.2.5.5, 4.4.2.1, 4.4.2.2.3

Protocol Version: 56a

☐ Operating Criteria

Criteria Section(s):

Criteria Date:

☐ Planning Criteria

Criteria Section(s):

Criteria Date:

☑ Tariff

Tariff Section(s): Attachment AE – 4.1.2.4
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**WORKING GROUP REVIEWS AND RECOMMENDATIONS**
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Reasons for Opposition:

**COMMENTS**

**Comment Author:** Kristen Darden (SPP) on behalf of the MWG
### Date Comments Submitted: 6/12/2018

**Description of Comments:** The MWG made minor changes to enhance clarity of language.

**Status:** MWG approved. Language incorporated.

### COMMENTS

**Comment Author:** Erin Cathey (SPP)

### Date Comments Submitted: 7/31/2018

**Description of Comments:** After further review, it became apparent that changing the market design to allow DVER control statuses to impact the market clearing processes would require corresponding changes to Desired Dispatch and the associated Settlement determinants dealing with Resource dispatchability. The definition for Desired Dispatch is revised below. Other revisions are to clean-up inconsistent terminology and to add Real Time Capability to the glossary.

**Status:** MWG reviewed, modified and approved. Language incorporated.

### COMMENTS

**Comment Author:** Kristen Darden (SPP) on behalf of the MWG

### Date Comments Submitted: 8/14/2018

**Description of Comments:** The MWG modified the definition of Desired Dispatch and made corresponding changes in the Protocols.

**Status:** MWG approved. Language incorporated.

### PROPOSED REVISION(S) TO SPP DOCUMENTS

**Market Protocols**

## Glossary

### Desired Dispatch

A MW value calculated from a Resource’s RTBM Energy Offer Curve between the minimum operating limit and the maximum operating limit that first exceeds the LMP at the Resource, that represents the point at which the Resource’s incremental Energy offer first exceeds the Resource’s RTBM-LMP—A Dispatchable Variable Energy Resource’s Desired Dispatch will be no greater
than the Resource’s Real-Time Capability, if available, or the lesser of the maximum operating limit and SPP’s output forecasted for that Resource.

**Real-Time Capability**
The amount (MW) of real power output the Resource is capable of instantaneously producing, excluding any dispatch, deployment, or curtailment instructions. This item is only required for Resources that are qualified to provide Operating Reserve as identified in section 6.1.8.

### 4.2.2.5.5 Dispatchable Variable Energy Resources

The following rules apply to Resources registered as Dispatchable Variable Energy Resources (“DVER”):

1. The Minimum Emergency Capacity Operating Limit, Minimum Economic Operating Capacity Limit and Minimum Normal Capacity Operating Limit submitted as part of the Day-Ahead Market and/or RTBM Resource Offer must be submitted as zero MW. Otherwise, the Resource Offer will be rejected;

2. For DVERs with an Emergency Maximum Capacity Operating Limit of less than 200MW, the maximum ramp rate between MW specified in the Ramp-Rate-Up Curve and Ramp-Rate Down Curve in the RTBM Resource Offer multiplied by 5 cannot exceed 40MW. For DVERs with an Emergency Maximum Capacity Operating Limit greater than or equal to 200MW, the maximum ramp rate between MW levels specified in the Ramp-Rate-Up Curve and Ramp-Rate-Down Curve in the RTBM Resource Offer multiplied by 5 cannot exceed 20% of the DVER’s Emergency Maximum Capacity Operating Limit;

3. For the RUC processes, the maximum operating limit shall be the lesser of the Emergency Maximum Capacity Operating Limit as specified in the DVER RTBM Offer and SPP’s output forecast for that DVER. DVERs for which SPP is calculating an output forecast are not eligible to receive RUC Make Whole Payments as described under Section 4.5.9.8;

4. For the Real-Time Balancing Market, DVER Dispatch Instructions are calculated assuming the DVER is dispatchable regardless of its Control Status. DVERs eligible to clear Regulation-Down must submit a Control Status of “Regulating” if capable of providing Regulation-Down. SPP will provide a dispatch flag to the DVER indicating whether or not the DVER should “follow” or “ignore” its Setpoint Instruction. Use of these dispatch flags in calculating Setpoint Instruction is described under Section 4.4.3.1. These flags are set as part of the RTBM solution as follows:

   a. The default value of the dispatch flag will be “ignore”. When the dispatch flag is “ignore”, the DVER’s maximum operating limit is set equal to the DVER’s actual output at the time of the current RTBM run;
(b) The dispatch flag will be set to “follow” if (i) the DVER is dispatched below its maximum operating limit or (ii) the DVER is issued an OOME, or (iii) the DVER is cleared for Regulation-Down;

(5) For the Real-Time Balancing Market for the current RTBM run, if the dispatch flag is “follow” as set by the previous RTBM run, then the DVER’s maximum operating limit in each subsequent Dispatch Interval is set equal to either:

(a) The lesser of (i) SPP’s output forecast for that DVER or (ii) the DVER’s Emergency Maximum Capacity Operating Limit; or

(b) The Emergency Maximum Capacity Operating Limit as specified in the DVER Offer if the SPP output forecast is not available for that DVER; or

(c) SPP’s output forecast for that DVER if the Emergency Maximum Capacity Operating Limit:
   (i) Was not submitted in the DVER Offer; or
   (ii) Was not updated in the Offer during the Operating Hour prior to the Operating Hour in which the Resource limit would apply but before the lead time described in Section 4.2.2; or
   (iii) Exceeds the maximum physical rating of the DVER that was submitted at market registration.

Such maximum operating limit continues to be set as described above until such time that the Resource’s Dispatch Instruction is equal to the maximum operating limit, after which, the DVER’s maximum operating limit is calculated as described under (4)(a) above.

4.4.2.1 Managing Regulation Control Status Prior to Operating Hour

SPP selection of Regulation Qualified Resources, Regulation-Up Qualified Resources and Regulation-Down Qualified Resources to be available to be cleared for Regulation-Up Service and/or Regulation-Down Service within the Operating Hour will be performed as follows:

(1) Prior to each Operating Hour, SPP will select sufficient on-line regulation qualified Resources to meet the Regulation-Up and Regulation-Down requirements using the results of the most recently completed RUC analysis. Prior to the Operating Hour, in order to prepare for the loss of regulating capability on one or more selected Resources within the Operating Hour and support reliable operations, SPP will also select, as necessary, additional regulation qualified Resources using the selection process described under (2) below.

(2) SPP will, in order to support reliable operations, update the Current Operating Plan by selecting additional regulation qualified Resources as being required to be eligible to clear Regulation-Up Service and/or Regulation-Down Service. MCRs that have registered under the option described under Section 6.1.7.1 are not eligible for regulation selection in any hour in which they are transitioning from one configuration to another. SPP will use the following criteria to select such
additional Resources in merit order to the extent that such Resources can be deployed reliably. Merit order prices for provision of Regulation-Up and Regulation-Down will be calculated as follows:

\[
\text{Regulation-Up Merit Order Price} = \text{Capacity Cost} + \text{RTBM Regulation-Up Offer} + \text{Regulation-Up Energy Lost Opportunity Cost}
\]

\[
\text{Regulation-Down Merit Order Price} = \text{Capacity Cost} + \text{RTBM Regulation-Down Offer} + \text{Regulation-Down Energy Increased Cost}
\]

(a) Capacity Cost - For Regulation Qualified Resources, Regulation-Up Qualified Resources and Regulation-Down Qualified Resources, Capacity LOC is equal to the sum of Regulation Maximum Capacity Uncompensated Cost and Regulation Minimum Capacity Uncompensated Cost, where Regulation Maximum Capacity Uncompensated Cost ($/MWh) is each Resource’s estimated uncompensated cost for lost Energy output between regulation maximum limit and Capacity–Desired Dispatch MW, and Regulation Minimum Capacity Uncompensated Cost ($/MWh) is each Resource’s estimated uncompensated cost for Energy output between Capacity–Desired Dispatch MW and regulation minimum limit that Resources Regulation-Up Offer.

(i) Regulation Maximum Capacity Uncompensated Cost = \[
\left[ \left[ \text{Max} \left(0, \text{estimated LMP} \text{($/MWh)} - \text{Energy Offer Curve cost of Energy between regulation maximum limit and Capacity–Desired Dispatch MW ($/MWh)}\right) \right] \cdot \left[ \text{Max} \left(0, \text{Desired Dispatch MW} - \text{regulation maximum limit}\right) \right] \right] / \left[ \text{regulation ramp rate} \cdot 5 \text{ minutes} \right].
\]

(ii) Regulation Minimum Capacity Uncompensated Cost = \[
\left[ \left[ \text{Max} \left(0, \text{Energy Offer Curve cost of Energy between Capacity–Desired Dispatch MW ($/MWh)} - \text{estimated LMP ($/MWh)}\right) \right] \cdot \left[ \text{Max} \left(0, \text{regulation minimum limit} - \text{Desired Dispatch MW}\right) \right] \right] / \left[ \text{regulation ramp rate} \cdot 5 \text{ minutes} \right].
\]

(iii) Capacity–Desired Dispatch MW = A MW value calculated from a Resource’s RTBM Energy Offer Curve between the minimum operating limit and the maximum operating limit that first exceeds the LMP at the Resource. A Dispatchable Variable Energy Resource’s Desired Dispatch will be no greater than the Resource’s Real-Time Capability, if available, or the lesser of the maximum operating limit and SPP’s output forecasted for that Resource, the MW point on the Resource’s Energy Offer Curve between economic minimum and economic maximum at which the price point on the curve is equal to the estimated LMP.

4.4.2.2.3 Control Status

The Control Statuses below apply to all Resources except for that is not a DVER, NDVERs and or a Resources that is not using the Quick Start Resource Logic. The Control Status as it applies to DVERs...
and NDVERs is discussed in Section 4.2.2.5.5 and 4.2.2.5.6, respectively. The Control Status as it applies to Quick Start Resource Logic is discussed in Section 4.4.2.3.1.

(A) **Off-line (Control Status 0)** – This Control Status indicates that the Resource is off-line and not available to the RTBM. This status is reserved for Resources which are generating 0 MWs. This includes Resources which are disconnected from the grid for an approved outage and Resources lacking a current commitment or start instruction.

(B) **Non-Regulating (Control Status 1)** – This Control Status indicates that the Resource is on-line and capable of following a Dispatch Instruction and/or Contingency Reserve Deployment Instruction. Resources in Control Status of Non-Regulating will not be eligible to clear Regulation-Up Service and/or Regulation-Down Service.

(C) **Regulating (Control Status 2)** – This Control Status indicates that the Resource is on-line and capable of following a Dispatch Instruction, Contingency Reserve Deployment Instruction, and/or Regulation Deployment.

(D) **Manual (Control Status 3)** – This Control Status indicates that the Resource is on-line but not capable of following a Dispatch Instruction. This status is reserved for generating Resources operating under the following conditions:

1. Start-up
2. Shut-down
3. Testing
4. Experiencing, or recovering from, a unit trip
5. Generating at an output to which the Resource is not capable of responding to a Dispatch Instruction
6. Condensing
7. Experiencing environmental, control or mechanical issues
8. Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility.

While operating in “Manual” Control Status and as long as the Resource does not have an active Contingency Reserve Deployment Instruction, the Setpoint Instruction is an echo of the latest SCADA output or State Estimator solution output, if SCADA is not available. If the Resource has an active Contingency Reserve Deployment Instruction and is now in “Manual” Control Status, the Resource will receive a Setpoint Instruction that is equal to the sum of the RTBM Dispatch Instruction and the Contingency Reserve Deployment Instruction, until the Contingency Reserve Deployment Instruction is terminated.
Attachment AE

4.1.2.4 Dispatchable Variable Energy Resource

Each Market Participant may submit Resource Offers for Dispatchable Variable Energy Resources using the same Offer parameters available to any other Resource, except that:

1. The minimum operating limits specified in the Resource Offer must be equal to zero;
2. The maximum operating limits for use in the Day-Ahead RUC and the Intra-Day RUC shall be calculated by the Transmission Provider as equal to the lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider’s output forecast for that Resource to the extent that such output forecast is available;
   a) Dispatchable Variable Energy Resources for which the Transmission Provider is calculating an output forecast are not eligible to receive RUC make whole payments as described under Section 8.6.5 of this Attachment AE.
3. For the purposes of issuing Dispatch Instructions to Resources as described under Section 4.1.2.4(6) of this Attachment AE, Dispatchable Variable Energy Resources with a maximum capability of less than two-hundred (200) MWs, submitted ramp rates multiplied by five (5) cannot exceed forty (40) MWs;
4. For the purposes of issuing Dispatch Instructions to Resources as described under Section 4.1.2.4(6) of this Attachment AE, Dispatchable Variable Energy Resources with a maximum capability of greater than or equal to two-hundred (200) MWs, submitted ramp rates multiplied by five (5) cannot exceed twenty percent (20%) of the maximum capability;
5. For the RTBM, during times when the Transmission Provider issues a Dispatch Instruction to a Dispatchable Variable Energy Resource to reduce output, the Resource’s Setpoint Instruction shall be equal to the sum of the Resource’s Dispatch Instruction and any Regulation-Down deployment, even if the Market Participant has indicated that the Resource is not dispatchable;
(6) For the RTBM, during times when the Transmission Provider issues a Dispatch Instruction to a Dispatchable Variable Energy Resource to increase output in Dispatch Intervals immediately following a Dispatch Interval in which a Dispatch Instruction was issued to reduce output as described in Section 4.1.2.4(5) of this Attachment AE, the Transmission Provider shall calculate the Resource maximum operating limit to be equal to:

(a) The lesser of the maximum operating limits submitted in the Resource Offer or the Transmission Provider’s Dispatchable Variable Energy Resource output forecast for that Resource to the extent the such forecast is available, except that, the Transmission Provider’s output forecast for the Resource shall be used for the maximum operating limits when: (i) maximum operating limits have not been submitted; (ii) the maximum operating limits submitted in the Resource Offer are more than thirty (30) minutes old; or (iii) the maximum operating limits submitted in the Resource Offer exceed the maximum physical rating of the Resource as stated during market registration; or

(b) The maximum operating limits submitted in the Resource Offer if the Transmission Provider’s Dispatchable Variable Energy Resource output forecast for that Resource is not available.

The Transmission Provider shall continue to calculate such maximum operating limits for each subsequent Dispatch Interval until the maximum operating limit is equal to the lesser of the Transmission Provider’s Dispatchable Variable Energy Resource output forecast for that Resource or the maximum operating limit submitted in the Resource Offer, after which, the Dispatchable Variable Energy Resource’s maximum operating limit shall be calculated as described in Section 4.1.2.4(7) of this Attachment AE.

(7) For the RTBM, during times other than those times described under Section 4.1.2.4(6) of this Attachment AE, the Resource’s maximum operating limit for use in the current Dispatch Interval shall be equal to the Resource’s actual output at the start of the Dispatch Interval and the ramping restrictions described under Sections 4.1.2.4(3) and (4) of this Attachment AE shall not apply.

(8) Dispatchable Variable Energy Resources may also receive an OOME according to the rules in Section 6.2.4 of this Attachment AE.
**Revision Request Recommendation Report**

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### SUBMITTER INFORMATION

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<th>Company: Xcel Energy Services, Inc.</th>
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<tr>
<td>Email: <a href="mailto:carrie.e.dixon@xcelenergy.com">carrie.e.dixon@xcelenergy.com</a></td>
<td>Phone: 303.571.6597</td>
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### 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 current MCR design does not allow MPs to submit a Minimum Down Time for an entire combined cycle facility; it only permits individual registered configurations. Additionally, the current MCR design requires that each registered configuration is capable of starting up from an off-line state and capable of being de-committed. These aspects of the current MCR design pose a significant risk to a combined cycle resource as it may be subject to commitment and de-commit instructions that the resource is not physically capable of complying with.

For example, an MCR configuration for the duct range of a combined cycle resource can have a much shorter minimum down time requirement than that of a configuration for a single or incremental combustion turbine. Under the current MCR design, it is possible for a combined cycle resource to be fully de-committed to an offline state from its duct range configuration, which also entails the de-commitment of a combustion turbine (or turbines). Once the resource is desynchronized, the MCR is eligible for recommitment once the minimum down time for the duct configuration has been met, which potentially may be a shorter minimum down time than is required for the combustion turbine. The scope of the current MCR commitment logic is limited to evaluating only the configuration that the MCR was de-committed from, not the minimum down time of the entire resource. By narrowing the commitment logic in this way, a MCR can receive a commitment instruction that potentially violates physical equipment limitations.

This revision request proposes to add two additional commitment parameters for MCRs to resolve the issue described above: ‘Group Minimum Down Time’ and ‘Plant Minimum Down Time’.

Additional language has also been added to the “Resource Commitment Parameter Relationships” section of the Protocols to improve the runtime and down time parameter logic for MCRs. Specifically, the Sync-to-Min Time and Min-To-Off Time will no longer be added to the submitted Minimum Down Time or Group Minimum Down Time when the MCR is transitioning between operational configurations. The addition of Sync-To-Min Time and Min-To-Off Time should only apply when the resource is synchronizing or de-synchronizing.

These design enhancements will improve the transparency of an MCR’s operational capability which will result in improved economic evaluation of these resources in both the DAMKT and RUC processes.

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

The addition of ‘Group Minimum Down Time’ and ‘Plant Minimum Down Time’ parameters to the current MCR design will prevent combined cycle resources from being committed and de-committed in a manner that potentially violates physical equipment limitations. The addition of these parameters will also potentially facilitate extending the MCR design option to non-combined cycle resource types in the future if the MWG elects to pursue that optionality in the future.

### SPP STAFF ASSESSMENT

SPP staff supports this revision request.

### IMPACT

Page 1 of 23
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:

Estimated Cost: $37,896  Estimated Duration: 4 months

Primary Working Group Score/Priority: Low

SPP DOCUMENTS IMPACTED

☒ Market Protocols  Protocol Section(s): 1, 4.2.2.1, 4.2.2.4, Exhibit 4-7, 6.1.7.1  Protocol Version: 59a

☐ Operating Criteria  Criteria Section(s):  Criteria Date:

☐ Planning Criteria  Criteria Section(s):  Criteria Date:

☒ Tariff  Tariff Section(s): Attachment AE – 1.1 Definitions G, P, 4.1

☐ Business Practice  Business Practice Number:

☒ Integrated Transmission Planning (ITP) Manual  Section(s):

☐ Revision Request Process  Section(s):

☐ Minimum Transmission Design Standards for Competitive Upgrades (MTDS)  Section(s):

☐ Reliability Coordinator and Balancing Authority Data Specifications (RDS)  Section(s):

☐ SPP Communications Protocols  Section(s):

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

Primary Working Group: MWG  Date: 8/14/2018
Action Taken: Unanimously Approved
Date: 9/11/2018
Action Taken: Unanimously Approved Impact Analysis with Low Rank

Secondary Working Group: ORWG  Date: 9/6/2018
Action Taken: Unanimously Approved

Secondary Working Group: RTWG  Date: 9/27/2018
Action Taken: Unanimously Approved

MOPC  Date: 10/16/2018
Action Taken: Abstained:
Opposed:
### Reasons for Opposition:

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### Comments

**Comment Author:** Kristen Darden (SPP) on behalf of the MWG  
**Date Comments Submitted:** 8/14/2018

**Description of Comments:** The MWG aligned the Tariff references in the proposed definitions in the Protocols to current formatting. The comments also include an updated Exhibit 4-7, in Section 4.2.2.4 (Resource Commitment Parameter Relationships).

**Status:** MWG approved; Language incorporated.

### PROPOSED REVISION(S) TO SPP DOCUMENTS

#### Market Protocols

1. **Glossary**

   - **Group Minimum Down Time**
     
     As defined in Attachment AE of the Tariff.

   - **Plant Minimum Down Time**
     
     As defined in Attachment AE of the Tariff.
4.2.2.1 Resource Offer Parameters

The following Resource Offer parameters must be submitted to constitute a valid offer for use in either the DA Market or RTBM:

1. Resource Name (as specified during Market Registration and cannot be changed as part of Resource Offer submittal);
2. Start-Up Offer ($/Start, Hot, Intermediate and Cold – Hourly Unit Commitment Parameter)\(^1\);
3. Mitigated Start-Up Offer ($/Start, Hot, Intermediate and Cold – Hourly Unit Commitment Parameter)\(^1\);
4. No-Load Offer ($/Hour)\(^1\);
5. Mitigated No-Load Offer ($/Hour)\(^1\);
6. Energy Offer Curve (MW, $/MWh, up to 10 price/quantity pairs, monotonically non-decreasing $/MWh, increasing MW and slope or block option);
   a. Block and slope pairs may not coexist. The Resource Offer in effect for any given period of time must be comprised by all block or all slope price/quantity pairs.
      i. For a JOU under the Combined Resource Option, the block or slope option must be selected by, or on behalf of, the designated Asset Owner. All other JOU Share Resource owners of that JOU must use the option selected by the designated Asset Owner. All other JOU Share Resource owners of that JOU will be converted to the option selected by the designated Asset Owner if submitted differently.
   b. The price of all MWhs below the first pricing point MWh is equal to the first pricing point price. The price by all MWhs above the last pricing point MWh is equal to the last pricing point price.
   c. Under the slope option, the set of price points that are submitted are used as the beginning and ending values for calculating a linear slope for each set of beginning and ending values. Therefore, each MW between the two price points has a different price due to the interpolation of the submitted price points. Under the block option, each MW between the two MW points is offered at the price of the larger MW point. Exhibit 4-5 illustrates Energy Offer Curves developed from submitted price/MWh pairs for both the slope and block options.

\(^{1}\) For Market Participants that have registered a JOU under the Combined Resource Option (see Section 6.1.6.2), this value must be submitted by or on behalf of the designated Asset Owner and represents the value for the entire Physical JOU Resource. See Section 4.2.2.5.4.)
Exhibit 4-1: Energy Offer Curve Development

(7) Mitigated Energy Offer Curve (MW, $/MWh, up to 10 price/quantity pairs, monotonically non-decreasing $/MWh, increasing MW and slope or block option);

(a) Block and slope pairs may not coexist. The Resource Offer in effect for any given period of time must be comprised of all block or all slope price/quantity pairs.

(i) For a JOU under the Combined Resource Option, the block or slope option must be selected by or on behalf of the designated Asset Owner. All other JOU Share Resource owners of that JOU must use this selected option. All other JOU Share Resource owners of that JOU will be converted to the option selected by the designated Asset Owner if submitted differently.

(8) Regulation-Up Offer ($/MW);

(9) Mitigated Regulation-Up offer ($/MW);

(10) Regulation-Up Mileage Offer ($/MW) – Note that if Regulation-Up Offer is less than zero then Regulation-Up Mileage Offer must be equal to zero;

(11) Mitigated Regulation-Up Mileage Offer ($/MW);

(12) Regulation-Down Offer ($/MW);

(13) Mitigated Regulation-Down Offer ($/MW);

(14) Regulation-Down Mileage Offer ($/MW) - Note that if Regulation-Down Offer is less than zero then Regulation-Down Mileage Offer must be equal to zero;

(15) Mitigated Regulation-Down Mileage Offer ($/MW);

(16) Spinning Reserve Offer ($/MW);
(17) Mitigated Spinning Reserve Offer ($/MW);
(18) Supplemental Reserve Offer ($/MW);
(19) Mitigated Supplemental Reserve Offer ($/MW)
(20) Sync-To-Min Time (hours:minutes – Daily Unit Commitment Parameter)¹;
(21) Min-To-Off Time (hours:minutes – Daily Unit Commitment Parameter)¹;
(22) Start-Up Time (hours:minutes, Hot, Intermediate, Cold – Hourly Unit Commitment Parameter)¹;
(23) Hot to Intermediate Time (hours:minutes– Daily Unit Commitment Parameter)¹;
(24) Hot to Cold Time (hours:minutes– Daily Unit Commitment Parameter)¹;
(25) Maximum Daily Starts (Daily Unit Commitment Parameter)¹;
(26) Maximum Weekly Starts – rolling 7-day (Daily Unit Commitment Parameter)¹;
(27) Maximum Daily Energy (MWh – Daily Unit Commitment Parameter)¹;
  (a) For enforcement of the Maximum Daily Energy constraint, cleared Regulation-Up and
cleared Contingency Reserve will decrement the Resource’s total Maximum Daily Energy
by 50% of the cleared product.
  (b) For enforcement of the Maximum Daily Energy constraint, cleared Regulation-Down will
increment the Resource’s total Maximum Daily Energy allowed by 0% of the cleared product.
(28) Minimum Run Time (hours:minutes– Daily Unit Commitment Parameter)¹;
(29) Group Minimum Down Time (hours:minutes– Daily Unit Commitment Parameter) - Only
applicable to MCRs that have registered under the option described under Section 6.1.7.1.;
(30) Group Minimum Run Time (hours:minutes– Daily Unit Commitment Parameter) - Only
applicable to MCRs that have registered under the option described under Section 6.1.7.1;
(31) Plant Minimum Down Time (hours:minutes – Daily Unit Commitment Parameter) - Only
applicable to MCRs that have registered under the option described under Section 6.1.7.1.;
(32) Plant Minimum Run Time (hours:minutes – Daily Unit Commitment Parameter) - Only
applicable to MCRs that have registered under the option described under Section 6.1.7.1;
(33) Maximum Run Time (hours:minutes– Daily Unit Commitment Parameter)¹;
(34) Minimum Down Time (hours:minutes– Daily Unit Commitment Parameter)¹;
(35) Minimum Emergency Capacity Operating Limit (MW);
(36) Minimum Emergency Capacity Run Time (hours:minutes – Operations Information);
(37) Minimum Normal Capacity Operating Limit (MW);
(38) Minimum Economic Capacity Operating Limit (MW);
(39)(40) Minimum Regulation Capacity Operating Limit (MW);
(40)(41) Maximum Regulation Capacity Operating Limit (MW);
(41)(42) Maximum Economic Capacity Operating Limit (MW);
(42)(43) Maximum Normal Capacity Operating Limit (MW);
(43)(44) Maximum Emergency Capacity Operating Limit (MW);
(44)(45) Maximum Emergency Capacity Run Time (hours:minutes – Operations Information);
(45)(46) Maximum Quick-Start Off-line Supplemental Reserve Resource Response Limit (MW, this represents the maximum amount of Supplemental Reserve that may be supplied by an Off-line Quick-Start Supplemental Reserve Resource);1

(46)(47) Ramp-Rate-Up (curve, MW/Minute - for use when the Resource is not selected for Regulation-Up Service and/or Regulation-Down Service clearing and dispatched in the up direction). Ramp-Rate-Up submittal is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \( n \) segments where \( n \) will be defined by SPP, initially set to ten (10);

(a) Breakpoint Limit 1 – Resource MW output at which segment 1 Ramp-Rate-Up will apply. In the RTBM, if the actual measured MW during deployment is less than the Breakpoint Limit 1, the Ramp-Rate-Up in Block 1 will apply back to the actual measured MW.

(b) Block 1 Ramp Rate Up – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to Breakpoint Limit 1.

(c) Block 1 Ramp Rate Emergency – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to Breakpoint Limit 1 during an Emergency.

(d) Breakpoint Limit \( n \) – Resource MW output at which Ramp-Rate-Up changes from previous segment values to segment \( n \) values.

(e) Block \( n \) Ramp-Rate-Up – Rate at which Resource can change output upward in MW/min at output levels greater than or equal to the Breakpoint Limit \( n \)

(f) Block \( n \) Ramp-Rate-Up Emergency – Rate at which Resource can change output upward in MW/min at output levels greater than the Breakpoint Limit \( n \) and less than Breakpoint Limit \( n+1 \) during an Emergency.

(46)(47) Ramp-Rate-Down (curve, MW/Minute - for use when the Resource is not selected for Regulation-Up Service and/or Regulation-Down Service clearing and dispatched in the Down direction). Ramp-Rate-Down submittal is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \( n \) segments where \( n \) will be defined by SPP, initially set to ten (10);

(a) Breakpoint Limit 1 – Resource MW output at which segment 1 Ramp-Rate-Down will apply. In the RTBM, if the actual measured MW during deployment is less than the
Breakpoint Limit 1, the Ramp-Rate-Down in Block 1 will apply back to the actual measured MW.

(b) Block 1 Ramp Rate Down – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to Breakpoint Limit 1.

(c) Block 1 Ramp-Rate-Down Emergency – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to Breakpoint Limit 1 during an Emergency.

(d) Breakpoint Limit \( n \) – Resource MW output at which Ramp-Rate-Down changes from previous segment values to segment \( n \) values.

(e) Block \( n \) Ramp-Rate-Down – Rate at which Resource can change output downward in MW/min at output levels greater than or equal to the Breakpoint Limit \( n \).

(f) Block \( n \) Ramp-Rate-Down Emergency – Rate at which Resource can change output downward in MW/min at output levels greater than the Breakpoint Limit \( n \) and less than Breakpoint Limit \( n+1 \) during an Emergency

(47)(48) Turn-Around Ramp Rate Factor (a value between 0.01 and 1.00). A Resource’s ramping direction in the next Dispatch Interval is compared against its ramping direction in the current Dispatch Interval. If these two ramping directions are different, then the Turn-Around Ramp Rate Factor is applied to the Dispatch Instruction in the next Dispatch Interval, except in circumstances where the Resource is selected as available to be cleared for Regulation or the Resource is being sent an OOME instruction.

The ramping direction in the current Dispatch Interval is based on the actual output at the beginning of the current Dispatch Interval compared to the Dispatch Instruction at the end of the current Dispatch Interval. The direction of the next Dispatch Interval is determined by considering the actual output and ramp capability of the Resource at the time of the solution and comparing it to the next Dispatch Instruction;

(48)(49) Regulation Ramp Rate (curve, MW/Minute - for use when the Resource is selected for Regulation-Up Service and/or Regulation Down Service clearing). Regulation Ramp Rate submittal is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \( n \) segments where \( n \) will be defined by SPP, initially set to ten (10);

(a) Breakpoint Limit 1 – Resource MW output at which segment 1 Regulation Ramp Rate will apply. In the RTBM, if the actual measured MW during deployment is less than the Breakpoint Limit 1, the Regulation Ramp Rate in Block 1 will apply back to the actual measured MW.

(b) Block 1 Regulation Ramp Rate – Rate at which a Resource on Automatic Generation Control can change output in the up and down direction in MW/min at output levels greater than or equal to Breakpoint Limit 1.
(c) Breakpoint Limit \( n \) – Resource MW output at which Regulation Ramp Rate changes from previous segment values to segment \( n \) values.

(d) Block \( n \) Regulation Ramp Rate – Rate at which Resource on Automatic Generation Control can change output in the up and down direction in MW/min at output levels greater than or equal to the Breakpoint Limit \( n \).

Contingency Reserve Ramp Rate (curve, MW/Minute). Contingency Reserve Ramp Rate submittal is through a segmented profile as follows. Each profile will require at least one (1) segment and may have up to \( n \) segments where \( n \) will be defined by SPP, initially set to ten (10);

(a) Breakpoint Limit 1 – Resource MW output at which segment 1 Contingency Reserve Ramp Rate will apply. In the RTBM, if the actual measured MW during deployment is less than the Breakpoint Limit 1, the Contingency Reserve Ramp Rate in Block 1 will apply back to the actual measured MW.

(b) Block 1 Contingency Reserve Ramp Rate – Rate at which a Resource not on Automatic Generation Control can change output in the up direction in MW/min when deploying Contingency Reserve at output levels greater than or equal to Breakpoint Limit 1.

(c) Breakpoint Limit \( n \) – Resource MW output at which Contingency Reserve Ramp Rate changes from previous segment values to segment \( n \) values.

(d) Block \( n \) Contingency Reserve Ramp Rate – Rate at which Resource not on Automatic Generation Control can change output in the up direction in MW/min when deploying Contingency Reserve at output levels greater than or equal to the Breakpoint Limit \( n \).

Resource Status (see Section 4.2.2.2);

Maximum Transition State Supplemental Reserve Resource Response Limit (MW, this represents the maximum amount of Supplemental Reserve that may be supplied by MCRs as a result of transitioning to a higher configuration) – Only applicable to MCRs that have registered under the option described under Section 6.1.7.1;

Transition State Offer (Only applicable to MCRs that have registered under the option described under Section 6.1.7.1);

Mitigated Transition State Offer (Only applicable to MCRs that have registered under the option described under Section 6.1.7.1);

Transition State Time (Only applicable to MCRs that have registered under the option described under Section 6.1.7.1); and

JOU Ownership Percent Share (Daily Unit Commitment Parameter)\(^2\);

\(^2\) Only applicable for the designated Asset Owner identified by the Market Participant that has registered a JOU under the Combined Resource Option (see Section 4.2.2.5.4). A value for each Asset Owner must be submitted by or on behalf of the
4.2.2.4 Resource Commitment Parameter Relationships

When developing the time-related Resource Offer parameters relating to Resource commitment, Market Participants should assume the relationships shown in Exhibit 4-7.

1. A Resource’s physical minimum run time begins when the Resource is synchronized. After the amount of time defined by physical minimum run time, the Resource can be de-synchronized. For SCUC modeling purposes, Minimum Run Time should be submitted as the physical minimum run time described above minus the Sync-To-Min Time and the Min-To-Off Time.
   
   (a) For MCRs, Minimum Run Time is submitted for
      
      (i) Each registered operational configuration, as described under Section 6.1.7.1. For SCUC modeling purposes, Minimum Run Time should be submitted as the minimum amount of time the MCR must remain in the associated operational configuration before transitioning to a different operational configuration or taken offline;
      
      (ii) Each defined group of configurations (Group Minimum Run Time), as described under Section 6.1.7.1. For SCUC modeling purposes, Group Minimum Run Time should be submitted as the minimum amount of time the MCR group must remain in the associated operational configuration/s before transitioning to an operational configuration that is associated with a different MCR group or taken offline; and
      
      (iii) The entire MCR (Plant Minimum Run Time). For SCUC modeling purposes, Plant Minimum Run Time should be submitted as the physical minimum run time for the MCR minus the Sync-To-Min Time and the Min-To-Off Time.

2. A Resource’s physical maximum run time begins when the Resource is synchronized. After the amount of time defined by the physical maximum run time, the Resource must be de-synchronized. For SCUC modeling purposes, Maximum Run Time should be submitted as the physical maximum run time described above minus the Sync-To-Min Time and the Min-To-Off Time.

   (a) For MCRs, Maximum Run time is submitted for each registered operational configuration, as described under Section 6.1.7.1. For SCUC modeling purposes, Maximum Run Time should be submitted specific to the operational configuration.
A Resource’s physical minimum down time begins at the point in time when a Resource is desynchronized. After the amount of time defined by physical minimum down time, following desynchronization, the Resource can begin synchronizing to the grid again. For SCUC modeling purposes, the submitted Minimum Down Time should be equal to the physical minimum down time described above. Sync-To-Min Time and Min-To-Off Time are automatically added to the submitted Minimum Down Time and that value is used in SCUC.

(a) For MCRs, Sync-To-Min and Min-To-Off Time are not added to the submitted Minimum Down Time or Group Minimum Down Time when the MCR is transitioning between operational configurations or between groups of configurations. When the MCR is starting from an offline state, the Sync-To-Min Time and Min-To-Off Time are automatically added to the submitted Minimum Down Time and that value is used in SCUC. Minimum Down Time is submitted for:

(i) Each registered operational configuration, as described under Section 6.1.7.1. For SCUC modeling purposes, Minimum Down Time should be submitted as the minimum amount of time the MCR must remain offline or operate in a different operational configuration before the MCR can return to that operational configuration;

(ii) Each defined group of configurations (Group Minimum Down Time), as described under Section 6.1.7.1. For SCUC modeling purposes, Group Minimum Down Time should be submitted as the minimum amount of time the MCR group must remain offline or operate in an operational configuration that is associated with a different MCR group before the MCR can return to an associated operational configuration with that MCR group; and

(iii) The MCR (Plant Minimum Down Time), as described under Section 6.1.7.1. For SCUC modeling purposes, Plant Minimum Down Time should be submitted as the minimum amount of time the MCR must remain offline before the MCR can return online.

(2)(4) As a part of its Start-Up Offer, a Market Participant must submit a hot, intermediate, and cold start-up price per start. Two temporal parameters that are submitted in the Resource Offer define which of these three prices will be used: (i) Hot-to-Cold Time and (ii) Hot-to-Intermediate Time.

(a) A Resource’s physical hot-to-intermediate time represents the amount of time between Resource desynchronization and the next synchronization during which the Resource Hot Start-Up Offer will apply. For SCUC modeling purposes, the submitted Hot-to-Intermediate Time should be equal to the sum of the physical hot-to-intermediate time, the Sync-To-Min Time and the Min-To-Off Time for that Resource. If the Resource is committed in less than the Hot-to-Intermediate Time after its previous De-Commit Time, then the hot start-up price will be used in the Resource Offer. For example, if the physical hot-to-intermediate time is 4 hours, the Sync-To-Min Time is 1 hour and the Min-To-Off
Time is 1 hour, the submitted Hot-To-Intermediate Time should be 6 hours. If the Resource’s De-Commit Time is 10:00 AM, the Hot Start-Up Offer would apply for Resource commitments between 10:00 AM and 4:00 PM.

(b) A Resource’s physical hot-to-cold time represents the amount of time between Resource de-synchronization and the next synchronization during which the Resource Cold Start-Up Offer will apply. For SCUC modeling purposes, the submitted Hot-to-Cold Time should be equal to the sum of the physical hot-to-cold time, the Sync-To-Min Time and the Min-To-Off Time for that Resource. If the Resource is committed in greater than or equal to the Hot-to-Intermediate Time and less than the amount of time defined by Hot-to-Cold Time after its previous De-Commit Time, then the intermediate start-up price will be used in the Resource Offer. For example, if the physical hot-to-cold time is 8 hours, the Sync-To-Min Time is 1 hour and the Min-To-Off Time is 1 hour, the submitted Hot-To-Cold Time should be 10 hours. If the Resource’s De-Commit Time is 10:00 AM, the Cold Start-Up Offer would apply for Resource commitments after 8:00 PM.

(c) If the Resource is committed in greater than or equal to Hot-to-Cold Time after its previous De-Commit Time, then the cold start-up price will be used in the Resource Offer. Using the above Hot-To-Intermediate Time and Hot-To-Cold Time examples, if the Resource’s De-Commit Time 10:00 AM, the Intermediate Start-Up Offer would apply for Resource commitments between 4:00 PM and 8:00 PM.

Exhibit 4-2: Resource Commitment Parameter Relationships

Blue: Configuration 1
Red: Configuration 2
Green: Configuration 3

Starting at the end of Configuration 1’s desynchronization:
* The next time Configuration 1 can sync, is when the Minimum Down Time has been met.
* The next time Configuration 2 can sync, is when the Group Minimum Down Time has been met.
* The next time Configuration 3 can sync, is when the Plant Minimum Down Time has been met.
6.1.7 Combined Cycle Resource

In addition to the responsibilities described under Section 6.1.1, Market Participants registering a Resource as a combined cycle Resource shall register their Resources for Commercial Modeling purposes using one of the four options described below.

1. Each combustion turbine and steam turbine may be registered as a separate Resource asset. Each individual Resource asset will be assigned a unique Settlement Location and each Resource asset must be registered to the same Asset Owner.
   (a) Each Resource asset will be committed and dispatched as an independent Resource. Each individual Resource asset will be settled at its Settlement Location. Telemetering and Settlement meter data must be submitted for each registered Resource asset.
   (b) The Market Participant may optionally request that all Resource assets be registered at a Common Bus.

2. An aggregate unit configuration may be registered as a single Resource asset in the Commercial Model and is assigned an APNode Settlement Location.
   (a) The aggregate Resource asset will be committed and dispatched as a separate Resource and will be settled at its APNode Settlement location.
   (b) Settlement meter data must be submitted for the aggregate Resource;
   (c) Telemetering must be submitted for each component of the aggregate Resource that is modeled in the Network Model.

3. The combined cycle Resource may be registered in the Commercial Model as several “pseudo” unit assets, each unit representing a combination of one combustion turbine and a portion of a steam turbine. Each pseudo unit asset is assigned an APNode Settlement Location.
   (a) Each pseudo unit asset will be committed and dispatched as a separate Resource and will be settled at its APNode Settlement location.
   (b) Settlement meter data must be submitted for each individual pseudo unit asset.
   (c) Telemetering must be submitted for each component - of each individual pseudo unit asset that is modeled in the Network Model.
   (d) The Market Participant may optionally request that all pseudo unit assets be registered at a Common Bus.

4. The combined cycle Resource may be registered in the Commercial Model as a MCR as described in Section 6.1.7.1.
6.1.7.1 Multi-Configuration Combined Cycle Resource

The combined cycle Resource registered as a MCR shall be registered as a single parent Resource Asset with associated valid operating configurations. Additionally, a Resource registered as an MCR shall not be registered as a QSR.

(a) Market Participants using the combined cycle configuration based modeling option shall register the physical units that are part of the combined cycle Resource as well as the operational configuration modes representing a valid operating configuration of the combined cycle Resource. Each valid operating configuration is treated as a separate Resource in the market systems and may have Resource Offers submitted using the same Offer parameters as any other Resource. The physical unit data are referenced by the Network Model that needs detailed unit physical characteristics and parameters as inputs.

(b) Configuration Based modeling is only available for registered MCRs that are combined cycle Resources which can operate in more than one mode. The most operational configurations that can be registered per an MCR is three.

(c) Market Participants shall supply operating characteristics for each operational configuration of an MCR, including, but not limited to: location of physical Resource, Legal owner, Resource type set to MCR (see section 6.1.1), and all of the non-price related operating parameters listed under Section 4.2.2.1 for each operational configuration;

(d) Market Participants shall supply a state transition matrix for each operational configuration. The state transition matrix describes the state transition relationship between the individual operational configurations, and includes the following:

(i) **Transition Enabled**: a flag describing whether a configuration transition is allowed between two given configurations, in the direction of ‘From’ configuration towards ‘To’ configuration;

(ii) **Transition Cost**: the additional operational cost associated with a configuration transition, in the direction of ‘From’ configuration towards ‘To’ configuration;

(iii) **Transition Time**: the additional time needed to prepare for a configuration transition, in the direction of ‘From’ configuration towards ‘To’ configuration. During Transition Time, the Resource will not be eligible for clearing Operating Reserve;

Exhibit 6-2 provides an example of a state transition matrix for Transition Costs which indicates that switching to configuration 2 will result in a transition cost of $300.00, assuming the plant is operating in configuration 1 mode when the transition occurs.

**Exhibit 6-3: MCR Transition Cost Matrix**
Market Participants shall submit an MCR capability array. The capability array stores information on the physical units that can participate in the operational state described by a logical operational configuration. Exhibit 6-3 provides an example of a configuration capability array.

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<td>Configuration 2</td>
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<td></td>
<td>1,500</td>
</tr>
<tr>
<td>Configuration 3</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
</tbody>
</table>
(f) Market Participants may optionally define groups of operational configurations to which a Group Minimum Down Time and Group Minimum Run Time will apply. The Group Minimum Down Time and Group Minimum Run Time, if Groups are defined, will be used in addition to the Plant Minimum Down Time and Plant Minimum Run Time for more accurate operational modeling of the plant. Exhibit 6-4 shows an example of how a group definition might be defined for a 2 x 1 plant. Configuration 1 X 1 A is (CT1, ST); Configuration 1 X 1 B is (CT2, ST) and Configuration 2 X 1 C is (CT1, CT2, ST).

Exhibit 6-5: MCR Group Definition

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<thead>
<tr>
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<th>Configuration 1 X 1 B</th>
<th>Configuration 2 X 1 C</th>
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<tr>
<td>Group 2</td>
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Exhibit 6-5 shows the impact of the use of Plant Minimum Down Time, Plant Minimum Run Time, and Group Minimum Down Time, and Group Minimum Run Time on how the combined cycle plant is committed through various configurations.
Attachment AE

1.1 Definitions G

**Group Minimum Down Time**
For an MCR, the minimum length of time a defined group of configurations must remain offline following transition to a different defined group of configurations.

**Group Minimum Run Time**
For an MCR, the minimum length of time a defined group of configurations must run from the time the group is put online to the time the group is shut down.

1.1 Definitions P

**Plant Minimum Down Time**
For an MCR, the minimum length of time required following complete desynchronization that the entire combined cycle plant must remain offline prior to a subsequent synchronization.

**Plant Minimum Run Time**
For an MCR, the minimum length of time the combined cycle plant must run from the time the plant is committed to the time the plant is shut down.

4.1 Offer Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants may begin to submit Offers for use in the Day-Ahead Market and Offers for use in the RTBM. Day-Ahead Market Offers may be updated up to the close of the Day-Ahead Market and RTBM Offers may be updated thirty (30) minutes prior to each Operating Hour. Offer submittals shall conform to the following:

(1) Offers submitted in the Day-Ahead Market are independent from Offers submitted in the RTBM except that, if Regulation-Up Service and/or Regulation-Down Service is cleared in the Day-Ahead Market, Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources for use in the RTBM are set equal to the Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources submitted for use in the Day-Ahead Market;

(2) Market Participants may specify that the Offers submitted in the Day-Ahead Market also apply in the RTBM;
   (a) Such an Offer shall be rejected in the RTBM if the Market Participant has submitted a Resource commitment status of “not participating” as described in Section 4.1(10)(e) of this Attachment AE and the Resource is not participating in the Day-Ahead Market.

(3) Submitted Resource Offers will automatically roll forward hour to hour within each respective market only when no Resource Offer has been submitted for that interval;

(4) Offers may be submitted that vary for each hour of the Operating Day, except the Offer parameters related to unit commitment as defined in the Market Protocols for which a single value is submitted. These unit commitment Offer parameters will automatically roll forward in each hour of the subsequent Operating Day only when no unit commitment Offer parameters have been submitted for that Operating Day;

(5) Offers submitted for use in the RTBM are also used in the RUC;

(6) Resource Offers may only be submitted at Resource Settlement Locations, Import Interchange Transaction Offers may only be submitted at External Interface Settlement Locations and Virtual Energy Offers may be submitted at any Settlement Location;
(7) For Regulation Qualified Resources and Regulation-Up Qualified Resources, Market Participants may submit Regulation-Up Offers, Regulation-Up Mileage Offers, Spinning Reserve Offers and Supplemental Reserve Offers provided that if the Regulation-Up Offer is negative, the Regulation-Up Mileage Offer must equal zero. For Regulation-Down Qualified Resources and Regulation Qualified Resources, Market Participants may submit Regulation-Down Offers and Regulation-Down Mileage Offers provided that if the Regulation-Down Offer is negative, the Regulation-Down Mileage Offer must equal zero. For Spin Qualified Resources, Market Participants may submit Resource Offers for Spinning Reserve and Supplemental Reserve. For Supplemental Qualified Resources, Market Participants may submit Resource Offers for Supplemental Reserve. If a Spinning Reserve Offer is submitted for a Resource, and a Resource Offer for Supplemental Reserve is not submitted, then the Supplemental Reserve Offer is set equal to zero. Resource qualifications are verified by the Transmission Provider as part of the registration process as follows:

(a) A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as defined in Section 2.10.3 of this Attachment AE and must be capable of deploying one hundred percent (100%) of cleared Regulation-Up and/or Regulation-Down within the Regulation Response Time for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(b) A Spin Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Spinning Reserve and/or cleared Supplemental Reserve within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(c) Supplemental Qualified Resource:

(i) A Supplemental Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Supplemental Reserve from an off-line state within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.
(ii) Alternatively, an MCR may also become a Supplemental Qualified Resource by self-certifying that the MCR is capable of deploying 100% of cleared Supplemental Reserve through a transition to a higher capacity configuration within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(8) Resource Offers are limited by the Offer caps and floors specified in Section 4.1.1 of this Attachment AE;

(9) The Resource Offer parameters that constitute a valid Offer for use in either the Day-Ahead Market or RTBM are submitted using the data formats, procedures, and information defined in the Market Protocols and will include the following (as further defined in the Market Protocols):

- Resource Name
- Resource Type
- Start-up Offer
- No-Load Offer
- Energy Offer Curve
- Transition State Offer (for an MCR)
- Transition State Time (for an MCR)
- Regulation–Up and Regulation-Down Offers
- Regulation-Up Mileage and Regulation-Down Mileage Offers
- Spinning and Supplemental Reserve Offers
- Sync-To-Min and Min-To-Off Times
- Start-Up Time
- Hot to Intermediate and Hot to Cold Times
- Maximum Daily and Weekly Starts
- Maximum Daily Energy
- Maximum and Minimum Run Times
- Plant Minimum Down Time (for an MCR)
- Plant Minimum Run Time (for an MCR)
- Group Minimum Down Time (for an MCR)
- Group Minimum Run Time (for an MCR)
• Minimum Down Time
• Minimum Emergency Capacity Operating Limit and Run Time
• Minimum Normal, Economic, and Regulation Capacity Operating Limits
• Maximum Normal, Economic, and Regulation Capacity Operating Limits
• Maximum Emergency Capacity Operating Limits and Run Time
• Maximum Quick-Start Response Limit
• Maximum Transition State Supplemental Reserve Resource Response Limit (for an MCR)
• Ramp-Rate-Up and Ramp-Rate-Down
• Turn-Around Ramp Rate Factor
• Regulation Ramp Rate
• Contingency Reserve Ramp Rate
• Resource Status
• JOU Ownership Share
• JOU Minimum Physical Capacity Operating Limit
• JOU Minimum Physical Regulation Capacity Operating Limit

(10) Market Participants must specify a Resource commitment status as part of the Resource Offer using the data formats, procedures, and information defined in the Market Protocols. Market Participants use the commitment status to indicate:
   (a) Whether they are self-committing a Resource;
   (b) Whether the Resource may be committed by the Transmission Provider;
   (c) Whether the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or local reliability issue;
   (d) Whether the Resource is on an outage; or
   (e) Whether the Resource is not participating in the Day-Ahead Market.

(11) Market Participants must specify a Resource dispatch status as part of the Resource Offer using the data formats, procedures and information defined in the Market Protocols. Market Participants use the dispatch status to notify the Transmission Provider whether the Resource is:
   (a) Eligible for Energy Dispatch;
   (b) Eligible for Operating Reserve clearing; or
   (c) Self-scheduled for Operating Reserve.
If the dispatch status for a Resource does not indicate it is eligible for Energy Dispatch, then such Resource shall not be subject to charges and credits calculated under Section 8.6.15 of this Attachment AE and shall not be subject to the deviation calculations under Sections 8.6.7(A)(2)(e) and 8.6.7(A)(2)(g) of this Attachment AE.

(12) Resource limits submitted as part of the Resource Offer must pass the validation rules defined in the Market Protocols, otherwise, the Resource Offer will be rejected; and

(13) The Market Participant must comply with the must-offer requirements as defined in Section 2.11 of this Attachment AE.
Revision Request Comment Form

<table>
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<th>RR #: 323</th>
<th>Date: 9/27/2018</th>
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**SUBMITTER INFORMATION**

<table>
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<tr>
<th>Name: Marisa Choate on behalf of the RTWG</th>
<th>Company: Southwest Power Pool</th>
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</thead>
<tbody>
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<td>Email: <a href="mailto:mchoate@spp.org">mchoate@spp.org</a></td>
<td>Phone: 501.688.1707</td>
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**OBJECTIVE OF REVISION**

Objectives of Revision Request:

On February 15, 2018 FERC issued Order 841 to amend regulations such that barriers to the participation of Electric Storage Resources (ESRs) in the capacity, energy, and ancillary service markets are removed. FERC ordered RTO/ISOs to revise tariffs to establish a participation model consisting of market rules that, recognizing the physical and operational characteristics of ESRs, facilitates their participation in the RTO/ISO markets. FERC defines specific compliance requirements in the following areas: Compliance Timeline, Participation Model, Qualification Criteria, New/Existing Tariff Mechanisms, Eligibility Limited Only by Technical Capability, De-Rating, Capacity, Energy Schedules, Dispatchable and Can Set Wholesale Clearing Price, Preventing Conflicting Offers/Bids from the Same Resource, Hold Harmless/MWP, Accounting, Self-Managed State of Charge, Minimum Size, Wholesale LMP, Direct Metering, and Use of Existing Tariff Rules. On March 26, 2018, SPP submitted a request seeking clarification in four areas: 1) ESR definition, 2) impact on load registration requirements, 3) applicability of capacity market requirements, and 4) requirements to create a dispatchable load service.

SPP’s existing market design does not include a participation model that, recognizing the physical and operational characteristics of ESRs facilitates their participation in our market. ESRs may participate today as a traditional generator or a Dispatchable Demand Response Resource, which is limiting for storage technologies.

SPP began working to develop market design rules that would better incorporate ESRs in November 17, 2016 when FERC issued NOPR AD16-20-000 (Electric Storage Participation in RTO/ISOs). SPP has worked with stakeholders and ESR developers to better understand the technical capabilities of ESRs and how SPP’s market may best accommodate them according to their physical and operational characteristics.

The Market Working Group is the primary stakeholder group reviewing and providing input into the ESR market design. The MWG will discuss ESR design on a monthly basis through October 2018. In order to ensure a timely compliance filing, the MOPC and BOD needs to review and take action in advance of the FERC-mandated filing deadline of December 3, 2018.

**COMMENTS**

The RTWG, in accordance with the motion listed below, proposes the following revisions (highlighted in green) to provide additional clarification in Section 28.6 and to the No-Load Offer definition in Attachment AE.

September 27, 2018 RTWG meeting:

Motion by Tom Hestermann (Sunflower) seconded by Rob Janssen (Dogwood) that the RTWG has reviewed RR 323 and believes the Tariff revisions implement the market protocols as presented. The RTWG recommends that the revisions made to Section 28.6 of the Tariff to be included in RR 323. The motion passed with five abstaining (Every, KMEA, MJMEUC, Tenaska, Xcel, AECC).

Reasons for abstaining:

Tenaska: I abstained because it is not consistent with all of the requirements in FERC Order 841.
In the Main Body of the SPP Tariff:

Section 1 Definitions

**Electric Storage Resource (“ESR”)**

A resource capable of receiving electric energy and storing it for later injection of electric energy to the grid. A resource that is either (1) physically incapable of injecting electric energy to the Transmission System due to its design or configuration or (2) contractually barred from injecting electric energy to the Transmission System is excluded from this definition.

**Market Storage Resource (“MSR”)**

As defined in Attachment AE of this Tariff.

II. POINT-TO-POINT TRANSMISSION SERVICE

13.7 Classification of Firm Transmission Service

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for long-term firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for short-term firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for long-term firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of
Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for short-term firm Transmission Service. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedules 7 and 11. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. In the event that a Transmission Customer (including third-party sales by a Transmission Owner) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, except for an MSR under instruction as specified in Section 2.17 of Attachment AE, the Transmission Customer shall pay the following penalty (in addition to the applicable charges for all of the firm capacity actually used): 100% of the Firm Point-To-Point Transmission Service charges under Schedules 7 and 11 for the period for which the unreserved service was actually used. The charges for the unreserved service shall be based upon the duration of the period when the unreserved capacity was used. For example, one hour shall be billed at the charge for weekday deliveries, repeated daily use of unreserved capacity within a seven day period shall increase the duration of the period to a weekly duration and multiple instances of unreserved use during more than one seven day period during a calendar month shall increase the duration of the period to a monthly duration. The Transmission Provider shall compensate the Transmission Owners for 100% of the (i) Firm Point-To-Point Transmission Service charge, (ii) Base Plan Zonal Charge and (iii) Region-wide Charge for the period for which they have provided service. The penalty revenues in excess of the amount distributed to Transmission Owners shall be used to reduce the Schedule 1-A charges.
collected by the Transmission Provider from the Transmission Customers. All Transmission Customers, except the penalized Transmission Customer, shall receive a reduction of Schedule 1-A charges pursuant to this section. Such penalty revenues shall be distributed by the Transmission Provider to Transmission Customers on a pro-rata basis of each Transmission Customer’s monthly Schedule 1-A charge, except for the penalized Transmission Customer, for the next billing period ending at least 15 calendar days after the date the Transmission Provider collects the penalty revenues from the penalized Transmission Customer. For the amounts exceeding reserved capacity, the Transmission Customer also must purchase losses as required by this Tariff.

14.5 Classification of Non-Firm Point-To-Point Transmission Service:
Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider and Transmission Owners undertake no obligation under the Tariff to plan the Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedules 8 and 11. In the event that a Transmission Customer (including third-party sales by a Transmission Owner) exceeds its non-firm capacity reservation, except for an MSR under instruction as specified in Section 2.17 of Attachment AE, the Transmission Customer shall pay the following penalty (in addition to the charges for all of the non-firm capacity used): 100% of the Non-Firm Point-To-Point Transmission Service charges under Schedules 8 and 11 for the duration of the period when the additional service was used as specified below not to exceed one month for the amount in excess of such capacity reservation. An excess of one hour or less shall be billed at the charge for weekday deliveries, repeated daily use of unreserved capacity within a seven day period shall increase the duration of the period to a weekly duration and multiple instances of unreserved use during more than one seven day period during a calendar month shall
increase the duration of the period to a monthly duration. The Transmission Provider shall compensate the Transmission Owners for 100% of the (i) Non-Firm Point-To-Point Transmission Service charge, (ii) Base Plan Zonal Charge and (iii) Region-wide Charge for the period for which they have provided service. The penalty revenues in excess of the amount distributed to Transmission Owners shall be used to reduce the Schedule 1-A charges collected by the Transmission Provider from the Transmission Customers. All Transmission Customers, except the penalized Transmission Customer, shall receive a reduction of Schedule 1-A charges pursuant to this section. Such penalty revenues shall be distributed by the Transmission Provider to Transmission Customers on a pro-rata basis of each Transmission Customer’s monthly Schedule 1-A charge, except for the penalized Transmission Customer, for the next billing period ending at least 15 calendar days after the date the Transmission Provider collects the penalty revenues from the penalized Transmission Customer. For the amounts exceeding the non-firm capacity reservation, the Transmission Customer must purchase losses as required by this Tariff. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedules 8 and 11.

28.6 Restrictions on Use of Service:

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System except for service where the purchaser is a Network Customer of the Transmission Provider. In the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve its Network Load, it shall pay the penalty set forth in Section 13.7 for the amount of the service used to facilitate the wholesale sale.
Network Customer to charge an ESR that has been designated as Network Load is an acceptable use of Network Integration Transmission Service under this Tariff.

ATTACHMENT AE

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DEFINITIONS

Asset Owner Reserve Zone Load Ratio Share
The sum of an Asset Owner’s Reported Load, Self-Charging MSRs and Export Interchange Transactions in a Reserve Zone divided by the sum of all Asset Owners’ Reported Load, Self-Charging MSRs and Export Interchange Transactions in all Reserve Zones for a given hour.

Commit Time
The time specified by the Transmission Provider SPP or a local Transmission Operator in a commit order at which a Resource should be synchronized and at or above Minimum Economic Capacity Operating Limit. For an MSR, this is the time specified by the Transmission Provider or a local Transmission Operator in a commit order at which the Resource should be connected and at or above its Minimum Discharge Limit or its Minimum Charge Limit.

Discrete Delivery Point
An injection point or withdrawal point connected to the Transmission System at which Locational Marginal Prices are calculated.

Electric Storage Resource (“ESR”)
As defined in Section 1 of the Tariff

Electric Storage Resource Loss Factor
The factor that represents round-trip efficiency related to the amount of energy an ESR loses from charge to discharge. This loss factor is the ratio of (1) the energy the ESR is able to inject via discharge to (2) the energy withdrawn in order to store that charge.

Market Storage Resource (“MSR”)
An ESR that registers consistent with the requirements under Section 2.17 of this Attachment AE

Maximum Charge Limit
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum MW Level</td>
<td>The maximum MW level that an MSR is able to withdraw from the grid during normal operating conditions.</td>
</tr>
<tr>
<td>Maximum Charge Time</td>
<td>The maximum duration of time that an MSR is able to withdraw from the grid.</td>
</tr>
<tr>
<td>Maximum Discharge Limit</td>
<td>The maximum MW level that an MSR is able to inject into the grid during normal operating conditions.</td>
</tr>
<tr>
<td>Maximum Discharge Time</td>
<td>The maximum duration of time that an MSR is able to inject into the grid.</td>
</tr>
<tr>
<td>Maximum Emergency Charge Limit</td>
<td>The maximum MW level that an MSR is able to withdraw from the grid during an Emergency Condition.</td>
</tr>
<tr>
<td>Maximum Emergency Discharge Limit</td>
<td>The maximum MW level that an MSR is able to inject into the grid during an Emergency Condition.</td>
</tr>
<tr>
<td>Maximum State of Charge</td>
<td>The maximum State of Charge that should not be exceeded.</td>
</tr>
<tr>
<td>Minimum Charge Limit</td>
<td>The minimum MWs level an MSR is able to withdraw from the grid during normal operating conditions.</td>
</tr>
</tbody>
</table>
**Minimum Charge Time**
The minimum duration of time an MSR is able to withdraw from the grid.

**Minimum Discharge Limit**
The minimum MW level that an MSR is able to inject into the grid during normal operating conditions.

**Minimum Discharge Time**
The minimum duration of time that an MSR is able to inject into the grid.

**Minimum Emergency Charge Limit**
The minimum MWs level that an MSR is able to withdraw from the grid during an Emergency Condition.

**Minimum Emergency Discharge Limit**
The minimum MWs level that an MSR is able to inject into the grid during an Emergency Condition.

**Minimum State of Charge**
The minimum State of Charge that should be maintained.

**Min-To-Off Time**
The time for a Resource to de-synchronize from the grid starting from the Resource’s Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit as applicable.

**No-Load Offer**
The compensation request in a Resource Offer, in dollars, by a Market Participant representing the hourly fee for operating a synchronized Resource at zero (0) Megawatt output. For a generating
unit, No-Load Offers are generally representative of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output. For a Dispatchable Demand Response Resource or Block Demand Response Resource, No-Load Offers are generally representative of a combination of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output for Behind-The-Meter Generation and the ongoing hourly costs associated with manufacturing process changes associated with a reduction in load consumption. For an MSR, No-Load Offers are the cost to maintain a State of Charge when the MSR has a zero (0) MW output (i.e., the Resource is operating under a “No-Load” condition).

Real-Time Load Ratio Share

The sum of a Market Participant’s Reported Load, Self-Charging MSRs and Export Interchange Transactions at all Settlement Locations divided by the sum of all Market Participants’ Reported Load, Self-Charging MSRs and Export Interchange Transactions at all Settlement Locations for a given hour.

Self-Charging

Withdrawing Energy from the Transmission System without a Transmission Provider Dispatch Instruction to provide a service under the Tariff.

State of Charge

The amount of energy stored expressed in MWhs.

State of Charge Forecast

The projected State of Charge for the beginning of each market interval used in the Day-Ahead Market and the RUC.

Start-Up Time

The time required to start a Resource and reach the Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit as applicable following receipt of a start-up order from the Transmission Provider.
Sync-To-Min Time
The time for a Resource’s output to reach Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Minimum Charge Limit as applicable following synchronization to the grid.

Transmission System Injection
Injecting energy to the Transmission System, or providing other services under the Tariff that support the delivery of energy to the Transmission System, at a Discrete Delivery Point including a generator that is collocated with the load and exceeds the load that it is contractually permitted to supply at such Discrete Delivery Point. This does not include generators that are acting as transmission facilities.

2.2 Application and Asset Registration
(1) Applications for a Market Participant to provide services in the Integrated Marketplace must be submitted to the Transmission Provider prior to the expected date of participation consistent with Section 6.4 of the Market Protocols. Applications must conform to the procedures specified in the Market Protocols and may be rejected if not complete. New Market Participants will follow the timeframe as specified in Section 6.4 of the Market Protocols in addition to the detailed model update timing requirements in Appendix E of the Market Protocols.

(2) As part of the application process, Market Participants must register all Resources and load, including applicable load associated with Grandfathered Agreements (“GFAs”), Non-Conforming Load and Demand Response Load with the Transmission Provider in accordance with the registration process specified in the Market Protocols. As part of Resource registration, Market Participants must specify whether settlement meter data will be submitted on a gross basis or net basis, where gross meter data does not include reductions for auxiliary load and net meter data is gross meter data reduced by auxiliary load. Both Non-Conforming Load and Demand Response Load may only be associated with a single Price Node except that Non-Conforming Load and Demand Response Load

Commented [PK17]: Paragraph 29: “…Additionally, consistent with the NOPR proposal, we clarify that electric storage resources located on the interstate transmission system, on a distribution system, or behind the meter fall under this definition, subject to the additional clarifications provided below. By including all electric storage technologies, and by allowing resources that are interconnected to the transmission system, distribution system, or behind the meter to use the participation model for electric storage resources, we are ensuring that the market rules will not be designed for any particular electric storage technology.”
may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes. Non-participating embedded load and/or generation must either: (i) register its load and/or generation in the Integrated Marketplace; or (ii) transfer its load and/or generation to an external Balancing Authority.

(3) Market Participants may elect to define a single Settlement Location that aggregates multiple Meter Data Submittal Locations associated with their load assets. Market Participants may not aggregate multiple Resource Meter Data Submittal Locations into a single Resource Settlement Location unless the Resources are at the same physical and electrically equivalent injection point to the Transmission System.

(4) In addition to the responsibilities described in Section 4.1.2 of this Attachment AE and under the Market Protocols, Market Participants wishing to model each participant’s share of a Jointly Owned Unit as a separate Resource must choose one of the two options described below and provide the specified additional information. A Resource registered as a combined cycle Resource may not register as a Jointly Owned Unit.

(a) Individual Resource Option

Under the individual Resource option, each participant’s share is modeled as a separate Resource for the purposes of commitment and dispatch and each Resource may be committed independent of the other Resource shares.

The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

(1) Jointly Owned Unit maximum physical capacity operating limit;

(2) Jointly Owned Unit minimum physical capacity operating limit;

(3) Jointly Owned Unit minimum physical regulation capacity operating limit;
(3) Maximum physical ten (10) minute response from an off-line state.

(b) Combined Resource Option

Under the combined Resource option each participant’s share is modeled and must be registered as a separate Resource. Under this option, the commitment decision is made assuming that all Resource shares must be committed or none at all. Each Asset Owner of a Jointly Owned Unit under the combined Resource option must submit a zero for the Minimum Emergency Capacity Operating Limit, Minimum Normal Capacity Operating Limit, Minimum Regulation Capacity Operating Limit, and Minimum Economic Capacity Operating Limit. The Jointly Owned Unit minimum physical capacity operating limit and minimum physical regulation capacity operating limit when the Jointly Owned Unit is selected to Regulate, can be achieved by any combination of Jointly Owned Unit shares during the commitment period. A Jointly Owned Unit under the combined Resource option will be dispatched using an aggregated Energy Offer Curve. Once committed, each Jointly Owned Unit share is dispatched independently and is eligible for recovery of Start-Up Offer and No-Load offer costs as described under Sections 8.5.9 and 8.6.5 of this Attachment AE. This option must be selected if the eligibility criteria stated under the individual Resource option cannot be met.

The operating owner’s Meter Agent will be the Meter Agent for that Jointly Owned Unit unless each individual Jointly Owned Unit participant registers a Meter Agent for its share of the Resource.

Unless otherwise agreed to by the Jointly Owned Unit participants, the operating owner will be responsible for submitting the following data:

(2) Jointly Owned Unit maximum physical capacity operating limit;
(3) Jointly Owned Unit minimum physical capacity operating limit;
(4) Jointly Owned Unit minimum physical regulation capacity operating limit;
Maximum physical ten (10) minute response from an off-line state; and

Participant share percentage by Market Participant.

Market Participants may modify their registered assets in accordance with the asset registration procedures specified in the Market Protocols.

All loads and all Resources, excluding Behind-The-Meter Generation less than 10 Megawatts (“MWs”), must register. Failure or refusal to register a load will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that load with the Commission under the name of the (i) Network Customer, (ii) Transmission Customer, or (iii) Transmission Owner serving load under a Grandfathered Agreement for which the Transmission Owner is neither taking Network Integration Transmission Service nor Firm Point-To-Point Transmission Service. Failure or refusal to register a Resource will result in the Transmission Provider filing an unexecuted version of the service agreement as specified in Attachment AH of this Tariff for that Resource with the Commission under the name of the generation interconnection customer under an interconnection agreement with the Transmission Provider or the applicable Transmission Owner. In the case of a Qualifying Facility exercising its rights under PURPA to deliver all of its net output to its host utility, such registration will not require the Qualifying Facility to participate in the Energy and Operating Reserve Markets or subject the Qualifying Facility to any charges or payments related to the Energy and Operating Reserve Markets. Any Energy and Operating Reserve Market charges or payments associated with the output of the Qualifying Facility will be allocated to the Market Participant representing the host utility purchasing the output of the Qualifying Facility under PURPA, and the Market Participant will be provided the settlement data required to verify the settlement charges and payments.

A Market Participant wishing to Offer an External Resource in the Energy and Operating Reserve Markets will utilize an External Resource Pseudo-Tie in accordance with Attachment AO. In addition to the responsibilities outlined in
Attachment AO, the Market Participant registering the External Resource will be responsible for registering and performing all responsibilities that are required of Resources in the Energy and Operating Reserve Markets.

(8) A Market Participant wishing to offer Demand Response Load as a Demand Response Resource in the Energy and Operating Reserve Markets must include in its application and registration a certification that participation in the Energy and Operating Reserve Markets by its Demand Response Resource is not precluded under the laws or regulations of the relevant electric retail regulatory authority. Consistent with Section 2.8.1 of this Attachment, an aggregator of retail customers wishing to offer Demand Response Load in the form of a Demand Response Resource on behalf of one or more retail customers must also include in its application and registration a certification that participation of each retail customer is either: (1) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (2) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year. Demand Response Resources must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

(9) An aggregator of retail or wholesale customers offering Demand Response Load of one or more end-use retail customers or wholesale customers as a Demand Response Resource in the Energy and Operating Reserve Markets must be a Market
Participant, satisfying all registration and certification requirements applicable to Market Participants as well as certification consistent with Section 2.8 of this Attachment AE, as required.

(10) All Variable Energy Resources must register as a Dispatchable Variable Energy Resource except for (1) a wind-powered Variable Energy Resource with an interconnection agreement executed on or prior to May 21, 2011 and that commenced Commercial Operation before October 15, 2012 or (2) a Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility or (3) a non-wind powered Variable Energy Resource registered on or prior to January 1, 2017 and with an interconnection agreement executed on or prior to January 1, 2017. Variable Energy Resources included in (1) and (3) above may register as Dispatchable Variable Energy Resources if they are capable of being incrementally dispatched by the Transmission Provider. A Qualifying Facility exercising its rights under PURPA to deliver its net output to its host utility may register as a Dispatchable Variable Energy Resource if it is capable of being incrementally dispatched by the Transmission Provider and will be subject to the Dispatchable Variable Energy Resource market rules including Uninstructed Resource Deviation charges. Any Resource that has previously registered as a Dispatchable Variable Energy Resource shall not subsequently register as a Non-Dispatchable Variable Energy Resource.

(11) A Market Participant that is selling firm power to the load asset under a bilateral contract may, with the agreement of the buyer, register all or a portion of the buyer’s load as its load asset. For purposes of this Section 2.2(11) of this Attachment AE, the sale of firm power shall refer to power sales deliverable with firm transmission service, with the supplier assuming the obligation to serve the buyer’s load with both capacity and energy. For the purposes of Section 2.11.1 of this Attachment AE, such registration of the buyer’s load by the seller shall be accounted for by including such load in the seller’s Reported Load and not including such load in the buyer’s Reported Load, as described under Section 2.11.1(A)(1) of this Attachment.
AE, and such associated bilateral contracts shall not be included in either the buyer’s or seller’s net resource capacity described under Section 2.11.1(A)(4) of this Attachment AE.

(12) A Transmission Owner providing firm transmission service under a GFA eligible for GFA Carve Out must request removal of congestion and marginal loss charges and designate the GFA Responsible Entity within the timeframe set forth in Section 2.2 (1) of Attachment AE.

(13) A GFA Responsible Entity shall provide to the Transmission Provider the information necessary to administer the GFA Carve Out. The required information shall include the following:

(a) Resource Settlement Location;
(b) Load Settlement Location;
(c) The maximum MW capacity contracted under the GFA Carve Out;
(d) The identification of the GFA in Attachment W; and
(e) Any other information reasonably required by the Transmission Provider.

(14) Market Participants with assets interconnected to the Transmission System that are not participating in the Energy and Operating Reserve Markets must pseudo-tie the Resource or load out of the SPP Balancing Authority Area in accordance with Attachment AO. Such assets shall continue to be registered in the Integrated Marketplace for the purposes of accounting for congestion and loss charges between the Resource Price Node and the applicable External Interface Settlement Location as described under Sections 8.6.23 and 8.6.24 of this Attachment AE.

(a) To the extent that the SPP Balancing Authority or associated external Balancing Authority can no longer maintain the Resource pseudo-tie for reliability reasons, the Market Participant representing the pseudo-tied Resource must immediately reduce the output of the pseudo-tied Resource to the available pseudo-tie capability after receiving notification from the affected Balancing Authority of the reduced capability. A Market
Participant shall not generate any energy in excess of the available pseudo-tie capability after receiving such notification and shall not be compensated in the Energy and Operating Reserve Markets settlement for any energy generated in excess of the available pseudo-tie capability.

(15) Western-UGP shall provide to the Transmission Provider the information necessary to administer the FSE. The required information shall include the following:
   (1) Resource Settlement Locations;
   (2) Load Settlement Locations;
   (3) The maximum MW capacity contracted under the FSE;
   (4) The identification of the FSE Statutory Load Obligations as described in the SPP-Western-UGP NITSA; and
   (5) Any other information reasonably required by the Transmission Provider.

(16) The Transmission Provider shall establish FSE Transfer Points consistent with the FSE transmission service power flow impacts.

(17) A Market Participant registering a Staggered Start Resource shall attest that the Resource meets the Staggered Start Resource definition in this Attachment AE. The attestation shall contain sufficient detail regarding the specific circumstances of the Resource to demonstrate that it meets the definition of a Staggered Start Resource. A Market Participant that has registered a Staggered Start Resource shall change the registration status no later than thirty (30) business days from the date the Resource ceases to meet the Staggered Start Resource definition.

(18) A Market Participant registering an ESR must register as described in Section 2.17 of this Attachment AE.
   a) An ESR of at least 0.1 MW that is capable of Transmission System Injection or directly connected to the Transmission System must register; however, if the ESR is exclusively a transmission facility with recovery through transmission rates, registration is not required.
   b) A Market Participant registering an ESR that is not required to register under this Tariff must include in its application and registration a certification that

Commented [PK18]: Paragraph 51 of Order 841: “... require each RTO/ISO to revise its tariff to include a participation model consisting of market rules that, recognizing the physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets.”

This proposed language outlines the registration requirements of an ESR and MSR in the Marketplace.
the Resource’s participation in the Energy and Operating Reserve Markets is not precluded under the laws or regulations of the relevant electric retail regulatory authority. The ESR must meet all application, registration and technical requirements applicable to the Energy and Operating Reserve Markets.

1. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials.

2. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

2.8 Aggregators of Retail and Wholesale Customers

Aggregations shall be subject to the following requirements:

(a) Generation not directly connected to the Transmission System may be aggregated into a single Resource at a Discrete Delivery Point;

(b) All Resources in an aggregation shall be specifically identified.
2.8.1 Aggregators of Demand Response - Retail Customers

(1) An aggregator of retail customers offering a Block Demand Response Resource or a Dispatchable Demand Response Resource associated with one or more end-use retail customers in the Energy and Operating Reserve Markets must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants.

(2) For purposes of participation in the Energy and Operating Reserve Markets, an aggregator of retail customers may aggregate Demand Response Load associated with a Block Demand Response Load Settlement Location or Demand Response Load associated with a Dispatchable Demand Response Load Settlement Location of: (1) End-use retail customers of utilities that distributed more than 4 million MW hours (“MWh”) in the previous fiscal year, unless precluded by the laws or regulations of the relevant electric retail regulatory authority including state-approved retail tariff(s); and (2) End-use retail customers of utilities that distributed 4 million MWh or less in the previous fiscal year, where the relevant electric retail regulatory authority, including any state-approved retail tariff(s), affirmatively permits such customer’s demand response to be offered into the Energy and Operating Reserve Markets by an aggregator of retail customers. Aggregators of retail customers shall be treated comparably to other Market Participants offering Resources in the Energy and Operating Reserve Markets.

Aggregations pursuant to this section shall be subject to the following requirements:

(a) End-use customers may be aggregated into a single Dispatchable Demand Response Resource or a single Block Demand Response Resource. The Demand Response Load may be associated with an aggregated Price Node that contains multiple electrically equivalent Price Nodes, provided that such aggregated Price Node is served by the same retail provider;

(b) All end-use customers in an aggregation shall be specifically identified.
(c) For a Block Demand Response Resource or a Dispatchable Demand Response Resource of an aggregator of retail customers that chooses to measure demand reductions using the calculated Real-Time response methodology, a single hourly baseline for each registered Resource shall be used to determine settlements pursuant to Section 8 of this Attachment AE.
2.8.3 Aggregators of Other Resources

1. An aggregator of generation must be a Market Participant, satisfying all registration and certification requirements applicable to Market Participants. Aggregators shall be treated comparably to other Market Participants offering Resources in the Energy and Operating Reserve Markets.

2. For participation in the Energy and Operating Reserve Markets, an aggregator must include in its application and registration a certification that the aggregator is either: (a) not precluded by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed more than 4 million MWh in the previous fiscal year; or (b) affirmatively permitted by the laws or regulations of the relevant electric retail regulatory authority if the customer is served by a utility that distributed 4 million MWh or less in the previous fiscal year.

3. The Transmission Provider is not responsible for interpreting the laws or regulations of a relevant electric retail regulatory authority and shall be required only to verify that the Market Participant has included such a certification in its application materials. The Transmission Provider is not liable or responsible for Market Participants participating in the Energy and Operating Reserve Markets in violation of any law or regulation of a relevant electric retail regulatory authority including state-approved retail tariff(s).

2.11 Must-Offer Requirement

2.11.1 Day-Ahead Market

A. Each Market Participant must satisfy the must offer obligation for an Asset Owner as set forth in Section 2.11.1(B) of this Attachment AE based on the following criteria:

1. A Market Participant’s load for an Asset Owner for purposes of this section shall be equal to that Market Participant’s maximum hourly Reported Load for an Asset Owner for the Operating Day. Such Asset Owner’s Reported Load shall include load registered as described under Section 2.2(11) of this Attachment AE, where the buyer’s Reported Load shall be reduced by the amount of the buyer’s load...
registered by the seller and the seller’s Reported Load shall be increased by the amount of the buyer's load registered by the seller. If an MSR is Self-Charging during the maximum Reported Load hour, the Market Participant’s available generation that is used to satisfy the must offer obligation is reduced by the Self-Charging MW.

(2) A Market Participant’s daily Operating Reserve obligation for an Asset Owner shall be equal to the sum of that Market Participant’s maximum daily Regulation-Up Service, Regulation-Down Service and Contingency Reserve obligations for an Asset Owner as estimated by the Transmission Provider in accordance with Section 3.1.4(3) of this Attachment AE.

(3) A Market Participant may satisfy this requirement by offering Resources for an Asset Owner with a commitment status indicating either that the Market Participant is self-committing the Resource, the Resource may be committed by the Transmission Provider, or the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or Local Reliability Issue, as specified in Sections 4.1(10)(a), 4.1(10)(b), and 4.1(10)(c) of the Attachment AE.

(4) A Market Participant’s net resource capacity for an Asset Owner, for purposes of this section shall include:
   i. Offered capacity by Resources identified in Section 2.11.1(A)(3) of Attachment AE less the Operating Reserve obligation identified in Section 2.11.1(A)(2) of Attachment AE; and
   ii. Firm power purchases less firm power sales, except that, if the seller has registered the buyer’s load associated with a firm power sale as described in Section 2.2(11) of this Attachment AE, such firm power sale shall not act to increase the buyer’s net resource capacity or act to reduce the seller’s net resource capacity. For purposes of this Section 2.11.1 of this Attachment AE firm power purchases and firm power sales shall mean sales and purchases that are deliverable with transmission service comparable to Firm Point-To-Point Transmission Service or Firm Network Integration.
Transmission Service with the supplier assuming the obligation to provide both capacity and energy. Additionally, firm power purchases shall include an Asset owner’s share of a Jointly Owned Unit to the extent that such shares have not been registered as separate Resources either under Jointly Owned Unit individual Resource option or the Jointly Owned Unit combined Resource option as described under Section 2.2(4) of this Attachment AE.

In order to verify firm power purchases and firm power sales, supporting documentation must be provided to the Market Monitor upon request. Market Participants have the option to input information regarding firm power purchases and firm power sales into the Market Monitor website. If no information is input into this website, the Market Monitor will contact the Market Participant for that information. The Market Monitor may communicate with the counterparty to confirm the firm purchase or sale and will include the transacted MWs to calculate net resource capacity for both purchaser and seller. If one of the parties disputes the firm purchase or sale to the Market Monitor, then the firm purchase or sale will not be used in the calculation of either the purchaser’s or seller’s net resource capacity subject to any dispute resolution.

B. A Market Participant’s compliance with the must offer obligation for an Asset Owner is as follows:

(1) A Market Participant that has offered all of its available Resources for an Asset Owner, with a commitment status described in Sections 4.1(10)(a), 4.1(10)(b), and/or 4.1(10)(c) of this Attachment AE, for an hour of the Operating Day is deemed to be in compliance with the must offer requirement for that Asset Owner for that hour regardless of its maximum hourly Reported Load and/or, Operating Reserve obligation.

(2) A Market Participant that does not meet the condition described in Section 2.11.1(B)(1) of this Attachment AE for an Asset Owner for an hour of the Operating Day, but has net resource capacity for that Asset Owner for that hour greater than
or equal to 90% of its load for that Asset Owner as described in Section 2.11.1(A)(1) of this Attachment AE is deemed to be in compliance for that Asset Owner with the must offer requirement for that hour.

(3) To the extent that a Market Participant does not meet the conditions described in either Section 2.11.1(B)(1) or (2) for an Asset Owner, the Market Participant shall be deemed noncompliant with the must offer requirement for that Asset Owner for that hour and will be assessed a penalty for that hour as determined in Section 3.9 of Attachment AF of this Tariff.

C. Market Monitor shall monitor a Market Participant’s Load, Operating Reserve obligation, offered Resources and net resource capacity, for an Asset Owner for each hour of the Operating Day to determine whether the Market Participant has complied with the must offer obligation set forth in Section 2.11.1(B).
2.12 Non-Conforming Load
Market Participants must:

(1) Provide hourly estimates of their registered Non-Conforming Load to the Transmission Provider no later than 1445 hours Day-Ahead for the remainder of the Operating Day and for the next six (6) Operating Days;

(2) Update their submitted Non-Conforming Load estimates as described in the Market Protocols;

(3) Provide the Transmission Provider with actual Non-Conforming Load data in Real-Time to the extent that telemetering is available.

(4) Provide the Transmission Provider with the charging activity of an ESR not registered as an MSR.

2.17 Electric Storage Resource
ESRs may register as any valid Resource type and are subject to the same service provision rules as any other Resource within that type.

(1) If not registered as an MSR the energy withdrawal from the Transmission System must be included in a Load Settlement Location and are subject to the same rules as other Load.

(2) If an ESR is registered as an MSR, the following applies:
   a) MSRs may provide Energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve services upon meeting the technical and applicable requirements for these services in this Attachment AE and the Market Protocols.
   b) MSRs must provide offer parameters as prescribed in Section 4.1 of this Attachment AE.
   c) MSR Offer Curves may include negative MW values to account for the entire dispatchable range of the MSR.
d) As with other Resources, the metering requirements for MSRs include real-time and settlement quality metering. For MSRs that are not directly connected to the Transmission System, metering may include facilities used by the distribution company.

e) Self-Charging MSRs or MSRs charging beyond the instructed amount that are subject to all applicable transmission charges under the Tariff.

f) Market Participants registering an MSR must also register as a Transmission Customer.

   i. Market Participants may use hourly non-firm transmission service.
   
   ii. In the absence of explicit transmission service reservation arrangements by the Market Participant for the uninstructed energy withdrawals, the Market Participant will be billed the unreserved use rate as defined in Section 13.7 (c) or 14.5 of this Tariff.

   iii. Dispatch Instruction by the Transmission Provider for the MSR to provide a wholesale service that incidentally results in charging activity shall not be subject to a bill for transmission service during those actions.


g) The Real-Time energy consumption is settled at the LMP as per Section 8.3 of this Attachment AE.

   i. In the event that the MSR is not directly connected to the Transmission System and the distribution company is unable or unwilling to separate the charging activity from other retail service, the MSR will not be subject to settlement by the Transmission Provider for either the transmission charge or the energy consumption.
4.1 Offer Submittal

Beginning seven (7) days prior to the Operating Day, Market Participants may begin to submit Offers for use in the Day-Ahead Market and Offers for use in the RTBM. Day-Ahead Market Offers may be updated up to the close of the Day-Ahead Market and RTBM Offers may be updated thirty (30) minutes prior to each Operating Hour. Offer submittals shall conform to the following:

(1) Offers submitted in the Day-Ahead Market are independent from Offers submitted in the RTBM except that, if Regulation-Up Service and/or Regulation-Down Service is cleared in the Day-Ahead Market, Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources for use in the RTBM are set equal to the Regulation-Up Mileage Offers and/or Regulation-Down Mileage Offers for the associated Resources submitted for use in the Day-Ahead Market;

(2) Market Participants may specify that the Offers submitted in the Day-Ahead Market also apply in the RTBM;
   (a) Such an Offer shall be rejected in the RTBM if the Market Participant has submitted a Resource commitment status of “not participating” as described in Section 4.1(10)(e) of this Attachment AE and the Resource is not participating in the Day-Ahead Market.

(3) Submitted Resource Offers will automatically roll forward hour to hour within each respective market only when no Resource Offer has been submitted for that interval;

(4) Offers may be submitted that vary for each hour of the Operating Day, except the Offer parameters related to unit commitment as defined in the Market Protocols for which a single value is submitted. These unit commitment Offer parameters will automatically roll forward in each hour of the subsequent Operating Day only when no unit commitment Offer parameters have been submitted for that Operating Day;

(5) Offers submitted for use in the RTBM are also used in the RUC;
(6) Resource Offers may only be submitted at Resource Settlement Locations, Import Interchange Transaction Offers may only be submitted at External Interface Settlement Locations and Virtual Energy Offers may be submitted at any Settlement Location;

(7) For Regulation Qualified Resources and Regulation-Up Qualified Resources, Market Participants may submit Regulation-Up Offers, Regulation-Up Mileage Offers, Spinning Reserve Offers and Supplemental Reserve Offers provided that if the Regulation-Up Offer is negative, the Regulation-Up Mileage Offer must equal zero. For Regulation-Down Qualified Resources and Regulation Qualified Resources, Market Participants may submit Regulation-Down Offers and Regulation-Down Mileage Offers provided that if the Regulation-Down Offer is negative, the Regulation-Down Mileage Offer must equal zero. For Spin Qualified Resources, Market Participants may submit Resource Offers for Spinning Reserve and Supplemental Reserve. For Supplemental Qualified Resources, Market Participants may submit Resource Offers for Supplemental Reserve. If a Spinning Reserve Offer is submitted for a Resource, and a Resource Offer for Supplemental Reserve is not submitted, then the Supplemental Reserve Offer is set equal to zero.

Resource qualifications are verified by the Transmission Provider as part of the registration process as follows:

(a) A Regulation Qualified Resource, Regulation-Up Qualified Resource or Regulation-Down Qualified Resource must pass a specific regulation test as defined in Section 2.10.3 of this Attachment AE and must be capable of deploying one hundred percent (100%) of cleared Regulation-Up and/or Regulation-Down within the Regulation Response Time for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(b) A Spin Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Spinning Reserve and/or cleared Supplemental Reserve within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide
telemetered output data that meets the technical requirements specified in the Market Protocols.

(c) Supplemental Qualified Resource:

(i) A Supplemental Qualified Resource must self-certify that the Resource is capable of deploying one hundred percent (100%) of cleared Supplemental Reserve from an off-line state within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(ii) Alternatively, an MCR may also become a Supplemental Qualified Resource by self-certifying that the MCR is capable of deploying 100% of cleared Supplemental Reserve through a transition to a higher capacity configuration within the Contingency Reserve Deployment Period for a continuous duration of sixty (60) minutes and provide telemetered output data that meets the technical requirements specified in the Market Protocols.

(8) Resource Offers are limited by the Offer caps and floors specified in Section 4.1.1 of this Attachment AE;

(9) The Resource Offer parameters that constitute a valid Offer for use in either the Day-Ahead Market or RTBM are submitted using the data formats, procedures, and information defined in the Market Protocols and will include the following (as further defined in the Market Protocols):

(1) Resource Name
(2) Resource Type
(3) Start-up Offer
(4) No-Load Offer
(5) Energy Offer Curve
(6) Transition State Offer (for an MCR)
(7) Transition State Time (for an MCR)
(8) Regulation–Up and Regulation-Down Offers
(9) Regulation-Up Mileage and Regulation-Down Mileage Offers
(10) Spinning and Supplemental Reserve Offers
(11) Sync-To-Min and Min-To-Off Times
(12) Start-Up Time
(13) Hot to Intermediate and Hot to Cold Times
(14) Maximum Daily and Weekly Starts
(15) Maximum Daily Energy
(16) Maximum and Minimum Run Times
(17) Plant Minimum Run Time (for an MCR)
(18) Group Minimum Run Time (for an MCR)
(19) Minimum Down Time
(20) Minimum Emergency Capacity Operating Limit and Run Time (not applicable to an MSR)
(21) Minimum Normal, Economic, and Regulation Capacity Operating Limits (not applicable to an MSR)
(22) Maximum Normal, Economic, and Regulation Capacity Operating Limits (not applicable to an MSR)
(23) Maximum Emergency Capacity Operating Limits and Run Time (not applicable to an MSR)
(24) Maximum Quick-Start Response Limit
(25) Maximum Transition State Supplemental Reserve Resource Response Limit (for an MCR)
(26) Ramp-Rate-Up and Ramp-Rate-Down
(27) Turn-Around Ramp Rate Factor
(28) Regulation Ramp Rate
(29) Contingency Reserve Ramp Rate
(30) Resource Status
(31) JOU Ownership Share
(32) JOU Minimum Physical Capacity Operating Limit
(33) JOU Minimum Physical Regulation Capacity Operating Limit
(34) State of Charge Forecast (MSR only)
(35) Maximum and Minimum State of Charge (MSR only)
(36) Maximum and Minimum Charge Limit (MSR only)
(37) Maximum and Minimum Discharge Limit (MSR only)
(38) Maximum and Minimum Charge Time (MSR only)
(39) Maximum and Minimum Discharge Time (MSR only)
(40) ESR Loss Factor (Required for ESRs – including MSRs)
(41) Maximum and Minimum Emergency Charge Limit (MSR only)
(42) Maximum and Minimum Emergency Discharge Limit (MSR only)

(10) Market Participants must specify a Resource commitment status as part of the Resource Offer using the data formats, procedures, and information defined in the Market Protocols. Market Participants use the commitment status to indicate:
   (a) Whether they are self-committing a Resource;
   (b) Whether the Resource may be committed by the Transmission Provider;
   (c) Whether the Resource may be committed by the Transmission Provider only to alleviate an anticipated Emergency Condition or local reliability issue;
   (d) Whether the Resource is on an outage; or
   (e) Whether the Resource is not participating in the Day-Ahead Market.

(11) Market Participants must specify a Resource dispatch status as part of the Resource Offer using the data formats, procedures and information defined in the Market Protocols. Market Participants use the dispatch status to notify the Transmission Provider whether the Resource is:
   (a) Eligible for Energy Dispatch;
   (b) Eligible for Operating Reserve clearing; or
   (c) Self-scheduled for Operating Reserve.

If the dispatch status for a Resource does not indicate it is eligible for Energy Dispatch, then such Resource shall not be subject to charges and credits calculated under Section 8.6.15 of this Attachment AE and shall not be subject to the deviation calculations under Sections 8.6.7(A)(2)(e) and 8.6.7(A)(2)(g) of this Attachment AE.
(12) Resource limits submitted as part of the Resource Offer must pass the validation rules defined in the Market Protocols, otherwise, the Resource Offer will be rejected; and

(13) The Market Participant must comply with the must-offer requirements as defined in Section 2.11 of this Attachment AE.

5.1.2.1 Clearing During Capacity Shortage

(1) In the event of an Operating Reserve shortage in any hour, Scarcity Pricing shall be implemented.

(2) In the event of a capacity shortage to meet the fixed Demand Bids, fixed firm Export Interchange Transactions and Resources’ charge MWs in any hour, the fixed Demand Bids, fixed firm Export Interchange Transactions, and Resources’ charge MWs will be reduced on a pro-rata reduction basis based on the fixed-MW amounts to match the available capacity and Scarcity Pricing shall be implemented.

(3) If a transmission constraint cannot be relieved due to a shortage of capacity in any hour, the SCED algorithm will clear the bid-in demands on a pro-rata basis based upon the impact on relieving the constraint.

5.2.2 Day-Ahead Reliability Unit Commitment Execution

The Transmission Provider will perform a capacity adequacy analysis for the upcoming Operating Day using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider load forecast, Export Interchange Transactions, Instantaneous Load Capacity requirements, and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers.
(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined in the submitted Energy Offer Curve.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, up to the Resources’ Maximum Economic Capacity Operating Limit, Maximum Discharge Limit, or Minimum Charge Limit or Maximum Regulation Capacity Operating Limit if selected for Regulation-Up and/or Regulation-Down Service, and down to the Resources’ Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Maximum Charge Limit, or Minimum Regulation Capacity Operating Limit if selected for Regulation-Down and/or Regulation-Up Service. In addition, an MCR is not eligible to be selected for Regulation-Down Service and/or Regulation-Up Service in any hour in which it is transitioning between configurations.

(1) If this capacity plus Import Interchange Transactions is not sufficient to meet the system-wide SPP Mid-Term Load Forecast, Export Interchange Transactions, the upper bound of Instantaneous Load Capacity requirements and Operating Reserve requirements, the SCUC algorithm study will, in priority order: (1) curtail non-firm Export Interchange Transactions until the capacity shortage is eliminated; (2) incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limit, Maximum Emergency Discharge Limit, or Minimum Emergency Charge Limit, commit Resources with a commitment status of "reliability" as described in Section 4.1(10)(e) of this Attachment AE, Commit Status of Reliability on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement to the extent possible, (3) de-commit charging Resources that were committed in the Day-Ahead Market with a commitment status of "market" as described in Section 4.1(10)(e) of this Attachment AE until the capacity shortage is eliminated, and (4) de-commit self-committed charging Resources.
(2) If the sum of Self-Commmitted capacity at minimum output, Import Interchange Transactions, the lower bound of Instantaneous Load Capacity requirement and the system-wide Regulation-Down requirement is in excess of the sum of the SPP system-wide Mid-Term Load Forecast and Export Interchange Transactions, the RUC SCUC algorithm study will, in priority order: (1) curtail non-firm fixed Import Interchange Transactions until the capacity surplus is eliminated; (2) incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limit, Minimum Emergency Discharge Limit, or Maximum Emergency Charge Limit on an economic basis until the capacity surplus is eliminated while attempting to maintain the Regulation-Down requirement to the extent possible; (3) commit any available Resource with a commitment status of “reliability” as described in Section 4.1(10)(e) of this Attachment AE that is capable of charging, (4) de-commit Resources that were committed in the DA Market with a Commit Status of Market commitment status of “market” as described in Section 4.1(10)(e) of this Attachment AE until the capacity surplus is eliminated; and (4) de-commit Self-Committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular security constraint impacting only the Transmission System cannot be directly addressed within the SCUC algorithm and is not a Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such a Transmission System security constraint in accordance with its authority as Reliability Coordinator. Such manual commitments 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. Additionally, such manual commitments shall be selected by the Transmission Provider to ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers. The recovery of the compensation paid by the Transmission Provider for such committed Resources
under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.6.7(A) of this Attachment AE.

(4) A Local Reliability Issue may arise during the Day-Ahead Reliability Unit Commitment process. Such Local Reliability Issues may require manual commitment or decommitment to be issued to one or more Resources to resolve the reliability issue. In such cases, the Transmission Provider shall issue or the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider 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. To the extent that the Transmission Provider, at the request of a local transmission operator, issues instructions to a Resource to address a Local Reliability Issue, such Resource shall be eligible for compensation in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(5) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider, including such commitments made at the request of the local transmission operator to relieve known and recurring Local Reliability Issues in the Day-Ahead RUC. Such Resources will be compensated in the same manner as any other Resource. The recovery of such compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

5.2.3 Day-Ahead Reliability Unit Commitment Results

No later than two-and-one-half (2.5) hours following the start of the Day-Ahead RUC, the Transmission Provider shall communicate the following results to Market Participants. The Transmission Provider will update the Current Operating Plan, if needed,
and issue start-up and/or shut-down orders simultaneously, which may occur anytime after
the Transmission Provider posts the results of the Day-Ahead RUC. The Day-Ahead RUC
results include:

(1) For any future hours in which the Transmission Provider anticipates an emergency
situation, the Transmission Provider shall notify all Market Participants identifying:
the hours in which the emergency capacity of any Resources are expected to be
required; the hours in which Resources are identified for reliability only use, as
described in Section 4.1(10)(c) of this Attachment AE, are expected to be
committed; the hours in which non-firm fixed Export Interchange Transactions are
expected to be curtailed; and the hours in which non-firm fixed Import Interchange
Transactions are expected to be curtailed.

(a) Affected Market Participants will be notified at least ten (10) minutes prior
to the beginning of the Operating Hour but not more than thirty (30) minutes
prior to the beginning of the Operating Hour that the Maximum Emergency
Capacity Operating Limit, Maximum Emergency Discharge Limit, or
Minimum Emergency Charge Limit, as applicable, will be used; and

(b) Affected Market Participants will be notified at least ten (10) minutes prior
to the beginning of the Operating Hour but not more than thirty (30) minutes
prior to the beginning of the Operating Hour that the Minimum Emergency
Capacity Operating Limit, Minimum Emergency Discharge Limit, or
Maximum Emergency Charge Limit, as applicable, will be used.

(2) Using the results from the Day-Ahead RUC analysis, the Transmission Provider
will update the Current Operating Plan and will issue start-up and shut-down orders
as appropriate. The Transmission Provider can only de-commit Day-Ahead Market
committed Resources or move a Day-Ahead Market MCR from a higher capacity
configuration to a lower capacity configuration to address an anticipated excess
supply condition as described under Section 5.2.2(2)(b) of this Attachment AE
and/or to address any other Emergency conditions. If the Transmission Provider
de-commits a Transmission Provider committed Resource or moves an MCR from
a higher capacity configuration to a lower capacity configuration for any hour of
the Day Market commitment schedule, and causes that the Resource to buy back its Energy and/or Operating Reserve position at RTBM prices that exceed the Day Ahead Market prices for the comparable products, that Resource is eligible for compensation under Section 8.6.6(2) of this Attachment AE.

6.1.2 Intra-Day Reliability Unit Commitment Execution

Using the inputs described in Section 6.1.1, the Transmission Provider will perform a capacity adequacy analysis using the SCUC algorithm with the objective of committing Resources to meet the Transmission Provider’s load forecast, Export Interchange Transactions, Instantaneous Load Capacity requirements, and Operating Reserve requirements less Import Interchange Transactions over the Operating Day such that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers.

(1) Commitment costs used in the SCUC are defined as Start-Up Offer, No-Load Offer and incremental cost to operate at minimum output as defined on the submitted Energy Offer Curve. Incremental Energy costs above minimum output and Operating Reserve Offers are not considered by the SCUC in making commitment decisions.

(2) The SCUC algorithm will initially consider commitment of Resources not specified for reliability only use as described in Section 4.1(10)(c) of this Attachment AE, only including capacity up to the Resources’ Maximum Economic Capacity Operating Limits (or Maximum Regulation Capacity Operating Limits if selected for Regulation-Up Service and/or Regulation-Down), Maximum Discharge Limit or Minimum Charge Limit and down to the Resources’ Minimum Economic Capacity Operating Limits (or Minimum Regulation Capacity Operating Limits if selected for Regulation-Down Service and/or Regulation-Up), Minimum Discharge Limit or Maximum Charge Limit.
**Limit or Maximum Charge Limit.** In addition, MCRs are not eligible to be selected for Regulation-Up Service and/or Regulation-Down Service in any hour in which they are transitioning between configurations.

(a) If this capacity plus Import Interchange Transactions is not sufficient on a system-wide basis to meet the Transmission Provider’s load forecast, Export Interchange Transactions, the upper bound of Instantaneous Load Capacity requirement, and Operating Reserve requirements, the SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Export Interchange Transaction Bids until the capacity shortage is eliminated; and (2) Incorporate capacity up to Resources’ Maximum Emergency Capacity Operating Limits, Maximum Emergency Discharge Limit or Minimum Emergency Charge Limit and/or, commit Resources designated as reliability only use, as described in Section 4.1(10)(c) of this Attachment AE, on an economic basis until the capacity shortage is eliminated while attempting to maintain the Regulation-Up requirement; (3) de-commit charging Resources that were committed in the DA Market with commitment status of “market” as described in Section 4.1(10)(e) of this Attachment AE until capacity shortage is eliminated, and (4) de-commit self-committed charging Resources.

(b) If there is a system-wide capacity surplus calculated as the sum of self-committed capacity at minimum output, fixed Import Interchange Transactions, the lower bound of Instantaneous Load Capacity requirement, and the Regulation-Down requirements that is in excess of the sum of the Transmission Provider load forecast and fixed Export Interchange Transaction, the Day-Ahead Market SCUC algorithm will, in priority order: (1) Curtail non-firm fixed Import Interchange Transaction Offers until the capacity surplus is eliminated; (2) Incorporate capacity down to Resources’ Minimum Emergency Capacity Operating Limits, Minimum Emergency Discharge Limit or Maximum Emergency Charge Limit until the capacity surplus is eliminated while attempting to maintain the Regulation-Down
requirement; (3) De-commit Resources that were committed by the Transmission Provider in the Day-Ahead Market that were not self-committed until the capacity surplus is eliminated; and (4) De-commit self-committed Resources until the capacity surplus is eliminated.

(3) To the extent that a particular reliability issue impacting only the Transmission System cannot be directly addressed within the SCUC algorithm and is not a Local Reliability Issue, the Transmission Provider may manually commit Resources and/or decommit Resources, including self-committed Resources to alleviate such Transmission System reliability issues. Such manual commitments 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. The Transmission Provider shall ensure that commitment costs are minimized while adhering to Transmission System security constraints and the Resource operating parameter constraints submitted as part of the RTBM Offers. The recovery of the compensation paid by the Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider regionally as described under Section 8.6.7(A) of this Attachment AE.

(4) A Local Reliability Issue may arise during the Intra-Day Reliability Unit Commitment Process. Such Local Reliability Issue may require manual commitment or decommitment to be issued by the Transmission Provider to one or more Resources to resolve the Local Reliability Issue. Time permitting, the local transmission operator shall request the Transmission Provider to issue such instructions and any commitment by the Transmission Provider 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. To the extent that the Transmission Provider issues instructions to a Resource at the request of a local transmission operator to resolve a Local Reliability Issue, the Resource shall be eligible for compensation in the same manner as any other Resource. The recovery of the compensation paid by the
Transmission Provider for such committed Resources under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE. To the extent time does not permit, the local transmission operator may issue such instructions to the Resource if the Local Reliability Issue is a Local Emergency Condition. In such cases, the following shall take place:

(a) If initial instructions are issued by a local transmission operator, the transmission operator shall notify the Transmission Provider of the instructions given to the Resource.

(b) The transmission operator and Transmission Provider will coordinate to ensure subsequent instructions are provided by the Transmission Provider.

(c) The transmission operator shall log such instructions, and shall notify the Transmission Provider of such action. The Transmission Provider shall log such instructions as manual commitment or decommitment, as appropriate, as if it gave such instruction to the Resource.

(d) The Resource shall be eligible to receive the compensation for such instructions in the same manner as if it had been committed by the Transmission Provider; except that if the Market Monitor determines that the Resource selected in response to such instructions was selected in a discriminatory manner and the Resource was affiliated with the local transmission operator, such Resource shall not be eligible to receive compensation under Section 8.6.5 of this Attachment AE. Such determination shall be made by the Market Monitor using the standards and procedures set forth in Section 6.1.2.1 of this Attachment AE. Recovery of any compensation shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

(e) The Transmission Provider, local transmission operator, and Resource owners shall develop operating guides to be applied to manual commitments made by the Transmission Provider including such commitments made at the request of the local transmission operator or manual commitments made by the local transmission
operator during a Local Emergency Condition to relieve known and recurring Local Reliability Issues in the Intra-Day RUC. Such Resources will be compensated in the same manner as any other Resource. The recovery of the compensation paid by the Transmission Provider under Section 8.6.5 of this Attachment AE shall be collected by the Transmission Provider locally as described under Section 8.6.7(B) of this Attachment AE.

6.2.1.2 Intra-Operating Hour Inputs

Intra-operating hour inputs to the RTBM will include the following:

1. Latest State Estimator solution for:
   a. Distribution of load forecast throughout the Network Model;
   b. Latest transmission topology for the Network Model; and
   c. Backup initial Energy injection of Resources if SCADA not available;

2. Actual Real-Time Resource output data from latest SCADA snapshot to determine initial Energy injection of Resources, and Generator outages and Real-Time State of Charge (for MSR only);

3. Active transmission constraints;

4. Intra-operating hour adjustments to Interchange Transactions due to curtailments or initiation of a Reserve Sharing Event involving external Balancing Authorities;

5. Intra-operating hour adjustments to Resource Offer physical operating parameters due to changes in a Resource’s capability. Market Participants shall notify the Transmission Provider of a change in a Resource Offer physical operating parameter during an Operating Hour. For the current Operating Hour the Transmission Provider will make the requested modification to the Resource Offer physical operating parameter. For subsequent hours the Market Participant shall remain responsible for accurately reflecting Resource operating parameters in its Resource Offer submissions;

6. Intra-hour adjustments to selection of Resources to provide Regulation-Up Service or Regulation-Down Service to the extent that Resources selected as described under Section 6.2.1.1(4) become unavailable to provide regulation service;
(7) Transmission Provider load forecast;
(8) The Transmission Provider’s wind Resource MWh output forecast; and
(9) The Transmission Provider’s estimate of Parallel Flows.

6.4.1 Uninstructed Resource Deviation

The following rules apply to the calculation of Uninstructed Resource Deviation (‘‘URD’’).

(1) For the purposes of determining URD exemptions for Resources that are part of a Common Bus as described under Section 6.4.1.1(6) of this Attachment AE, each Asset Owner’s Resources’ combined average ramped MW Setpoint Instruction and combined actual average MW output at the Common Bus will be used to calculate URD at the Common Bus for the Dispatch Interval for each Asset Owner.

(2) A Resource’s URD is allocated a portion of the RUC make whole payment costs, as described under Section 8.6.7 of this Attachment AE, in any Dispatch Interval where Resource’s URD is outside of its Operating Tolerance unless that Resource has been exempted from URD.

(a) A generating unit Resource’s Operating Tolerance in each Dispatch Interval is equal to the Resource’s Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(b) A Dispatchable Demand Response Resource’s Operating Tolerance in each Dispatch Interval is equal to the resource’s Maximum Emergency Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(c) A Block Demand Response Resource’s Operating Tolerance in each Dispatch Interval is equal to the Resource’s Maximum Economic Capacity Operating Limit multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.
(d) The Common Bus Operating Tolerance for each Market Participant registered at a Common Bus is equal to the sum of that Market Participant’s Resources’ Maximum Emergency Capacity Operating Limits for Resources that are on-line multiplied by five percent (5%), subject to a minimum of five (5) MW and a maximum of twenty (20) MW.

(e) If the absolute value of a Resource’s URD is greater than the Resource’s Operating Tolerance in any Dispatch Interval, the Resource URD / 12 is included in the hourly allocation of RUC make whole payment cost allocation. The Hourly URD amount is calculated as the sum of Dispatch Interval URD for the hour. Additionally, if that Resource was eligible to receive a RUC make whole payment, the payment may be reduced in accordance with Section 8.6.5 of this Attachment AE.

(f) An MSR’s Operating Tolerance in each Dispatch Interval is equal to the greater of the absolute value of the Maximum Emergency Charge Limit and the Maximum Emergency Discharge Limit multiplied by 5%, subject to a minimum of 5 MW and a maximum of 20 MW.

8.1 Settlement Sign Conventions
For the purposes of settlement calculation of charges and payments described under this Section 8, negative signs shall reflect payments to Market Participants and positive signs to shall reflect charges to Market Participants. Throughout the settlement calculations, multiplication by \((-1)\) is used to attain the proper sign convention where needed. Injections to the Transmission System are negative values and withdrawals are positive values. Consistent with the injection and withdrawals, the following sign conventions for variables used in the settlement calculations are assumed as follows:

1. Cleared Resource MWh and Virtual Energy Offer MWh in the Day-Ahead Market is a negative value;

2. Cleared load MWh and Virtual Energy Bid MWh in the Day-Ahead Market is a positive value;

3. Import Interchange Transaction MWh is a negative value;
(4) Export Interchange Transaction MWh is a positive value;
(5) Cleared Operating Reserve MWs in the Day-Ahead Market and RTBM are positive values;
(6) All MWs associated with TCRs are positive values;
(7) Actual Meter values and telemetered/State Estimator values for Resource injections are negative values; and
(8) Actual meter values and telemetered/State Estimator values for load consumption or a Resource’s energy withdrawals exceeding energy production are positive values.

8.5.1 Day-Ahead Energy Amount

A Day-Ahead Market charge or payment for cleared Energy is calculated at each Settlement Location for each Asset Owner for each hour as follows:

(1) For Energy associated with loads and Self-Charging MSRs:
The Day-Ahead Asset Energy Hourly Amount =
(Day-Ahead LMP) * [(Day-Ahead Cleared Load Energy Hourly Quantity) - (Day-Ahead Asset Energy Hourly Bilateral Settlement Schedules)]
(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with that load Settlement Location.
(b) An Asset Owner’s Day-Ahead Cleared Load Energy Hourly Quantity is the MW quantity associated with cleared Demand Bids at that load Settlement Location as described under Section 5.1.3 of this Attachment AE.
(c) An Asset Owner’s Day-Ahead Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that load Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(2) For Energy associated with Resources and MSRs providing a market service:
The Day-Ahead Asset Energy Hourly Amount =
(Day-Ahead LMP) * [(Day-Ahead Cleared Resource Energy Hourly Quantity) - (Day-Ahead Asset Energy Hourly Bilateral Settlement Schedules)]
(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with that Resource Settlement Location.

(b) An Asset Owner’s Day-Ahead Cleared Resource Energy Hourly Quantity is the MW quantity associated with cleared Resource Offers at that Resource Settlement Location as described under Section 5.1.3 of this Attachment AE.

(c) An Asset Owner’s Day-Ahead Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that Resource Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(3) For Energy associated with Import Interchange Transactions:

\[ \text{Day-Ahead Non-Asset Energy Hourly Amount} = (\text{Day-Ahead LMP}) \times [(\text{Day-Ahead Cleared Import Energy Hourly Quantity}) - \text{Day-Ahead Non-Asset Energy Bilateral Settlement Schedules}] \]

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable External Interface Settlement Location.

(b) An Asset Owner’s Day-Ahead Cleared Import Energy Hourly Quantity is the MW quantity associated with cleared Import Interchange Transaction Offers at that External Interface Settlement Location as described under Section 5.1.3 of this Attachment AE.

(c) An Asset Owner’s Day-Ahead Non-Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that External Interface Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(4) For Energy associated with Export Interchange Transactions:

\[ \text{Day-Ahead Non-Asset Energy Hourly Amount} = (\text{Day-Ahead LMP}) \times [(\text{Day-Ahead Cleared Export Energy Hourly Quantity}) - \text{Day-Ahead Non-Asset Energy Bilateral Settlement Schedules}] \]

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable External Interface Settlement Location.
(b) An Asset Owner’s Day-Ahead Cleared Export Energy Hourly Quantity is the MW quantity associated with cleared Export Interchange Transaction Offers at that External Interface Settlement Location as described under Section 5.1.3 of this Attachment AE.

(c) An Asset Owner’s Day-Ahead Non-Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that External Interface Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(5) For Energy associated with remaining Bilateral Settlement Schedules:
Day-Ahead Non-Asset Energy Hourly Amount =
(Day-Ahead LMP) * [(Day-Ahead Non-Asset Energy Bilateral Settlement Schedules) * (-1)]
(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.
(b) An Asset Owner’s Day-Ahead Non-Asset Energy Hourly Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at Settlement Locations other than External Interface Settlement Locations, that Asset Owner’s load Settlement Locations or that Asset Owner’s Resource Settlement Locations, as submitted in accordance with Section 8.2.1 of this Attachment AE.

(6) For Energy associated with Virtual Energy Bids:
Day-Ahead Virtual Energy Hourly Amount =
(Day-Ahead LMP) * (Day-Ahead Cleared Virtual Energy Bid Hourly Quantity)
(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.
(b) An Asset Owner’s Day-Ahead Cleared Virtual Energy Bid Hourly Quantity is the MW quantity associated with cleared Virtual Energy Bids at that Settlement Location as described under Section 5.1.3 of this Attachment AE.

(7) For Energy associated with Virtual Energy Offers:
Day-Ahead Virtual Energy Hourly Amount =
(Day-Ahead LMP) * (Day-Ahead Cleared Virtual Energy Offer Hourly Quantity)

(a) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.

(b) An Asset Owner’s Day-Ahead Cleared Virtual Energy Offer Hourly Quantity is the MW quantity associated with cleared Virtual Energy Offers as described under Section 5.1.3 of this Attachment AE at that Settlement Location.
8.5.9 Day-Ahead Make Whole Payment Amount

(1) The Day-Ahead make whole payment amount is a payment to an Asset Owner and is calculated for each Resource with an associated Day-Ahead Market Commitment Period that was committed by the Transmission Provider including commitments from the Multi-Day Reliability Assessment as defined under Section 4.5.3 of this Attachment AE. Asset Owners of Resources previously committed by a local transmission operator to address a Local Emergency Condition are eligible to receive a Day-Ahead Market make whole payment if such commitment is included in the Day-Ahead Market; except that, if the Market Monitor determines such Resources were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the local transmission operator, then such Resources are not eligible to receive a Day-Ahead Market make whole payment. A payment is made to an Asset Owner when a Resource’s costs are greater than the Day-Ahead Market revenues received during the Resource’s Day-Ahead Market make whole payment eligibility period. The make whole payment is equal to this difference between those costs and revenues.

(2) A Resource’s Day-Ahead Market make whole payment eligibility period is equal to a Resource’s Day-Ahead Market Commitment Period except as defined herein. For Resources with an associated Day-Ahead Market Commitment Period that begins in one Operating Day and ends in the next Operating Day, two (2) Day-Ahead Market make whole payment eligibility periods are created. The first period begins in the first Operating Day in the hour that the Day-Ahead Market Commitment Period begins and ends in the last hour of the first Operating Day. The second period begins in the first hour of the next Operating Day and ends in the last hour of the Day-Ahead Market Commitment Period.

(3) The following cost recovery rules apply to each Day-Ahead Market make whole payment eligibility period. Offer costs are calculated using the Day-Ahead Market
Offer prices in effect at the time the commitment decision was made except under the situation described under Section (b)(iiv) below.

(a) There may be more than one Day-Ahead Market make whole payment eligibility period for a Resource in a single Operating Day for which a charge or payment is calculated. A single Day-Ahead Market make whole payment eligibility period is contained within a single Operating Day.

(b) A Resource’s Day-Ahead Market commitment level offer costs include Start-Up Offer, Transition State Offer, and RUC remainder amount (as described in Section 8.5.9(3)(b)(v) of this Attachment AE) for a Day-Ahead Market make whole payment eligibility period in which that Resource is committed with a Day-Ahead Market Resource Offer commitment status under Section 4.1(10)(a), (b) or (c) of this Attachment AE, including commitments from the Multi-Day Reliability Assessment as described under Section 4.5.3 of this Attachment AE. The commitment level cost eligible for recovery is calculated by subtracting all Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status as described under Sections 4.1(10)(a) of this Attachment AE from all eligible commitment level Offer costs required to execute the Day-Ahead schedule associated with the Day-Ahead Market make whole payment eligibility period. The resulting difference represents either a charge or a payment and is a cost component when determining a Day-Ahead Market make whole payment.

(i) In any Day-Ahead Market make whole payment eligibility period for which the Day-Ahead Market SCUC algorithm did not consider the Resource’s Start-Up Offer in the original commitment decision, except Day-Ahead Start-Up Offer costs associated with the commitments made under Sections 4.5 and 5.1.2(1)(b) of this Attachment AE that caused an additional scheduled start, the Resource’s Start-Up Offer shall equal zero.
(ii) A Resource’s Day-Ahead Market Start-Up Offer cost is not eligible for recovery in the following Day-Ahead Market make whole payment eligibility periods:

1. For any Day-Ahead make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s Day-Ahead Market Commit Time in addition to the Resource’s Sync-To-Min Time unless the Day-Ahead Market make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the one (1) hour in addition to the Resource’s Sync-To-Min Time; or

2. For any Day-Ahead make whole payment eligibility period for which a Staggered Start Resource is a Synchronized Resource prior to this commitment period at a time two (2) hours prior to that Resource’s Day-Ahead Market Commit Time in addition to the Resource’s Sync-To-Min Time unless the Day-Ahead Market make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the two (2) hours in addition to the Resource’s Sync-To-Min Time.

(iii) When a RUC commitment is made at a point in time after the existing Day-Ahead Market commitment was made, but the RUC commitment is scheduled for a time adjacent and prior to the existing Day-Ahead Market commitment, the cost considered at the point of adjacency between the RUC and Day-Ahead Market commitments will be allocated between the two commitments for make whole payment purposes as described in (1) and (2) below.
(1) The cost allocated to the RUC make whole payment will not be greater than the difference between: (a) the Day-Ahead Market Start-Up Offer and Transition State Offer costs at the adjacency point of the RUC and Day-Ahead Market commitment; and (b) Day-Ahead Market Start-Up Offer and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE commitment at the adjacency point.

(2) The commitment level cost in the Day-Ahead Market make whole payment is reduced by the non-negative cost allocated to the RUC make whole payment.

(iv) A Resource’s Day-Ahead Market Transition State Offer costs for a Day-Ahead Market commitment are eligible for recovery in the Day-Ahead Market make whole payment eligibility period except when the Day-Ahead Market SCUC algorithm did not consider the Resource’s Transition State Offer in the Day-Ahead commitment decision unless Transition State Offers costs are associated with manual commitments as described under Sections 4.5.2 and 5.1.2 of this Attachment AE.

(v) As described under Section 8.6.5(3)(g) of this Attachment AE, to the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the adjacent RUC make whole payment eligibility period, any remaining RTBM Start-Up cost is carried forward for recovery in the adjacent Day-Ahead make whole payment eligibility period.

(vi) When a Resource loses eligibility to recover a Day-Ahead Market Start-Up Offer cost for the reason described in Section 8.5.9(3)(b)(ii)(1) of this Attachment AE, to prevent overstating avoided costs, the commitment level cost is adjusted by the lesser
of: (a) the Resource’s Start-Up Offer cost and Transition State Offer cost associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE commitments; or (b) the ineligible Day-Ahead Market Start-Up Offer cost.

(vii) For each Day-Ahead Market make whole payment eligibility period within an Operating Day, a Resource’s eligible Start-Up cost is divided by the lesser of (1) the Resource’s applicable Minimum Run Time rounded down to the nearest hour or (2) twenty-four (24) hours, to achieve an hourly proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead commitments.

(1) If the number of participating hours of a Day-Ahead Market make whole payment eligibility period meets or exceeds the duration of the divisor as described in (vii) above, the full cost of the Start-Up Offer is included in the commitment level cost for the Day-Ahead Market make whole payment eligibility period.

(2) If the number of participating hours of a Day-Ahead Market make whole payment eligibility period is less than the duration of the divisor as described in (vii) above, the hourly proration is multiplied by the number of participating hours to achieve a single Start-Up Offer amount to be included in the commitment level cost for that Day-Ahead Market make whole payment eligibility period. Any remaining Day-Ahead Market Start-Up Offer cost will be included in the commitment level cost for the following and adjacent Day-Ahead Market make whole payment eligibility period in the next Operating Day.

(c) For an MCR, additional costs or revenues are incurred when the Resource has cleared Contingency Reserve in the Day-Ahead Market and must buy
back that position in Real-Time at an average hourly Real-Time MCP. These costs or revenues will be considered as an adjustment when determining a Day-Ahead Market make whole payment. These costs or revenues must be incurred during a time period in the Day-Ahead Market make whole payment eligibility period in which the Resource is transitioning in Real-Time due to a Day-Ahead scheduled transition that is not forced by the Resource Offer. The Market Participant may also be eligible for adjustments to a Day-Ahead Market make whole payment for costs or revenues incurred during transition if the Resource is transitioning in Real-Time in response to a local transmission operator to address a Local Emergency Condition, (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE) then such Resources are not eligible to receive an adjustment to a Day-Ahead make whole payment for these costs or revenues. In such cases, the adjustment is equal to the Real-Time MCP multiplied by the Day-Ahead Market cleared Contingency Resource MW amounts. Recovery of these costs of revenues is limited to the dispatch interval time periods defined by the Transition State Time submitted in the Resource Offer.

(d) If a Resource’s self-commitment period is less than the Resource’s Minimum Run Time, the Transmission Provider will relax the Resource’s Minimum Run Time to equal the self-commit period.

(e) If a Resource is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE in the Day-Ahead Market, the Resource will be eligible to recover applicable recurring costs as defined in Section 8.5.9(4)(a) of this Attachment AE for that period in the Day-Ahead Market make whole payment eligibility period.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given Day-Ahead Market make whole payment eligibility period is calculated as follows:

\[
\text{Day-Ahead Make Whole Payment Amount} = \text{\ldots}
\]
Maximum of [Either Zero or Sum of ((Day-Ahead Make Whole Payment Cost Amount in the Day-Ahead Market Make Whole Payment Eligibility Period) + (Day-Ahead Make Whole Payment Revenue Amount in the Day-Ahead Market Make Whole Payment Eligibility Period) + (Day-Ahead Make Whole Payment Commitment Cost))] * (-1)

(a) An Asset Owner’s Day-Ahead Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:
(i) Day-Ahead Market No-Load Offer,
(ii) Energy cost associated with cleared Resource Energy, including MSRs providing a market service, from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Resource Energy by the cost of such Energy as calculated from the Resource’s Day-Ahead Market Energy Offer Curve,
(iii) Regulation-Up Service cost associated with cleared Regulation-Up Service from Regulation-Up Service Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up Service by the cost of such Regulation-Up Service as calculated from the Resource’s Day-Ahead Market Regulation-Up Service Offer,
(iv) Regulation-Down Service cost, associated with cleared Regulation-Down Service from Regulation-Down Service Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Down Service by the cost of such Regulation-Down Service as calculated from the Resource’s Day-Ahead Market Regulation-Down Service Offer,
(v) Spinning Reserve cost, associated with: (1) cleared Spinning Reserve from Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared

...
Spinning Reserve by the Day-Ahead Spinning Reserve offer; and (2) cleared Spinning Reserve from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up for Spinning Reserve by the Day-Ahead Regulation-Up capability offer to the extent that Regulation-Up Service was cleared to meet the Spinning Reserve requirement. Such costs shall exclude Spinning Reserve and Regulation-Up costs associated with an MCR during a Day-Ahead Market scheduled transition time when the MCR is transitioning in the Real-Time Balancing Market,

(vi) Supplemental Reserve cost, associated with: (1) cleared Supplemental Reserve from Supplemental Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Supplemental Reserve by the Day-Ahead Supplemental Reserve Offer; (2) cleared Supplemental Reserve from Spinning Reserve Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Spinning Reserve for Supplemental Reserve by the Day-Ahead Spinning Reserve offer to the extent that Spinning Reserve was cleared to meet the Supplemental Reserve requirement; and (3) cleared Supplemental Reserve from Regulation-Up Offers as described under Section 5.1.3 of this Attachment AE, as calculated by multiplying cleared Regulation-Up for Supplemental Reserve by the Day-Ahead Regulation-Up capability offer to the extent that Regulation-Up Service was cleared to meet the Supplemental Reserve requirement. Such costs shall exclude Supplemental Reserve, Spinning Reserve, and Regulation-Up costs associated with an MCR during a Day-Ahead Market scheduled transition time when the MCR is transitioning in the Real-Time Balancing Market,
(vii) Day-Ahead Potential Unused Regulation-Up Mileage Make Whole Payment as calculated under Section 8.6.19(1)(b), and
(viii) Day-Ahead Potential Unused Regulation-Down Mileage Make Whole Payment as calculated under Section 8.6.20(1)(b),
(ix) Day-Ahead Combined Cycle Spinning Reserve Adjustment which is a charge or payment, as described in Section 8.5.9(3)(c) of this Attachment AE, associated with an MCR, which is not eligible to clear Spinning Reserve in RTBM during a Real-Time transition between configurations which was scheduled in a Day-Ahead Market make whole payment eligibility period, and
(x) Day-Ahead Combined Cycle Supplemental Reserve Adjustment which is a charge or payment, as described in Section 8.5.9(3)(c) of this Attachment AE, associated with an MCR, which is not eligible to clear Supplemental Reserve in RTBM during a Real-Time transition between configurations which was scheduled in a Day-Ahead Market make whole payment eligibility period.

(b) An Asset Owner’s Day-Ahead Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE is equal to the sum for all hours in the Day-Ahead Market Make Whole Payment Eligibility Period of:

(i) Energy revenue associated with cleared Resource Energy, and MSRs providing a market service, from Resource Energy Offers as described under Section 5.1.3 of this Attachment AE, calculated by multiplying Resource Energy by Day-Ahead LMP at that Resource Settlement Location, and
(ii) The sum of the revenues calculated under Section 8.5.2, 8.5.3 and 8.5.4, 8.6.19(1) and 8.6.20(1) for that eligible Resource.
An Asset Owner’s Day-Ahead Make Whole Payment Commitment Cost Amount for each eligible Resource in the Day-Ahead Market Make Whole Payment Eligibility Periods is equal to:

(i) Day-Ahead Market Start-Up Offer or any RUC remainder amount as described in Section 8.6.5(3)(f) of this Attachment AE, plus

(ii) Day-Ahead Transition State Offer (for an MCR), plus

(iii) Any amount of Start-Up costs where the Resource loses eligibility to recover as described in Section 8.5.9(3)(b)(v) of this Attachment AE, minus

(iv) Any amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 8.5.9(3)(b)(ii) of this Attachment AE, minus

(v) All Start-Up and Transition State Offer costs associated with a Day-Ahead Market Resource Offer commitment status as defined under Sections 4.1(10)(a) of this Attachment AE.
8.5.10 Day-Ahead Make Whole Payment Distribution Amount

A Day-Ahead Market system-wide and local charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 8.5.9 of this Attachment AE. The system-wide amount will be determined by multiplying an Asset Owner’s system-wide distribution volume by a daily system-wide Day-Ahead Market make whole payment rate as described in this Section 8.5.10. The local amount for each Local Settlement Area impacted by a Local Reliability Issue will be determined as described in Section 8.6.7(B) of this Attachment AE.

The Day-Ahead System-Wide Make Whole Payment Distribution Amount shall be calculated as follows:

\[
\text{Day-Ahead System-Wide Make Whole Payment Distribution Amount} = (\text{Day-Ahead SPP System-Wide Make Whole Payment Distribution Rate}) \times (\text{Day-Ahead System-Wide Make Whole Payment Distribution Quantity})
\]

(1) The Day-Ahead SPP System-Wide Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 8.5.9, excluding make whole payments made to Resources committed to address a Local Reliability Issue or a Local Emergency Condition, divided by the sum of all Asset Owners’ Day-Ahead System-Wide Make Whole Payment Distribution Quantities for all Settlement Locations for the entire Operating Day.

(2) An Asset Owner’s Day-Ahead System-Wide Make Whole Payment Distribution Quantity at a Settlement Location for an hour is equal to that Asset Owner’s cleared Energy withdrawals at that Settlement Location for that hour. An Asset Owner’s Energy withdrawal at a Settlement Location is calculated as the sum of cleared Demand Bids, cleared Self-Charging MSR Offers, Export Interchange Transaction Bids and Virtual Energy Bids at that Settlement Location.
8.5.21 GFA Carve Out and FSE Distribution Daily Amount
The Transmission Provider shall perform the following calculation for each day for each Asset Owner and Settlement Location to ensure that the Day Ahead GFA Carve Out Daily Amount is distributed to all non GFA Carve Out load and non FSE load on a daily load ratio share basis, and that the Transmission Provider is revenue neutral.

GFA Carve Out Distribution Daily Amount =
GFA Revenue Inadequacy Daily Amount * Asset Owner Daily Distribution Factor * (-1)

Where:
(1) The GFA Revenue Inadequacy Daily Amount is equal to the sum of all GFA Carve Out charges and payments calculated under Section 8.5.18 of this Attachment AE for that day; and
(2) An Asset Owner’s Daily Distribution Factor is equal to:
   (a) The sum for all hours in the Operating Day of the Maximum of (i) zero or (ii) the Asset Owner’s hourly Reported Load and an MSR’s hourly Self-Charging MW, plus hourly Export Interchange Transactions minus the Asset Owner’s hourly GFA Carve Out load minus the Asset Owner’s hourly FSE load;
   Divided by,
   (b) The sum for all Asset Owners and Settlement Locations of the values calculated in Section 8.5.21(2)(a).

8.5.22 GFA Carve Out and FSE Distribution Monthly Amount
The Transmission Provider shall perform the following calculation for each month for each Asset Owner and Settlement Location to ensure the Day Ahead GFA Carve Out Monthly Amount is distributed to all non GFA Carve Out load and non FSE load on a monthly load ratio share basis and that the Transmission Provider is revenue neutral.
GFA Carve Out Distribution Monthly Amount =

GFA Revenue Inadequacy Monthly Amount * Asset Owner Monthly Distribution Factor
* (-1)

Where:

(1) The GFA Revenue Inadequacy Monthly Amount is equal to the sum of all GFA
Carve Out charges and payments calculated under Section 8.5.19 of this Attachment AE;
and

(2) An Asset Owner’s Monthly Distribution Factor is equal to:
    (a) The sum for all hours in the month of the Maximum of (i) zero or (ii) the
        Asset Owner’s hourly Reported Load and an MSR’s hourly Self-Charging MW,
        plus hourly Export Interchange Transactions minus the Asset Owner’s hourly GFA
        Carve Out load minus the Asset Owner’s hourly FSE load;
        Divided by,
    (b) The sum for all Asset Owners and Settlement Locations of the values
calculated in Section 8.5.22(2)(a).
8.5.23 GFA Carve Out and FSE Distribution Yearly Amount

The Transmission Provider shall perform the following calculation for each year for each Asset Owner and Settlement Location to ensure the Day Ahead GFA Carve Out Yearly Amount is distributed to all non GFA Carve Out load and non FSE load on an annual load ratio share basis and that the Transmission Provider is revenue neutral.

\[
\text{GFA Carve Out Distribution Yearly Amount} = \text{GFA Revenue Inadequacy Yearly Amount} \times \text{Asset Owner Yearly Distribution Factor} \times \frac{-1}{(1)}
\]

Where:

1. The GFA Revenue Inadequacy Yearly Amount is equal to the sum of all GFA Carve Out charges and payments calculated under Section 8.5.20 of this Attachment AE; and
2. An Asset Owner’s Yearly Distribution Factor is equal to:
   (a) The sum for all hours in the year of the Maximum of (i) zero or (ii) the Asset Owner’s hourly Reported Load and an MSR’s hourly Self-Charging MW, plus hourly Export Interchange Transactions minus the Asset Owner’s hourly GFA Carve Out load minus the Asset Owner’s hourly FSE load, divided by:
   (b) The sum for all Asset Owners and Settlement Locations of the values calculated in Section 8.5.23(2)(a) of this Attachment AE.
8.5.25 Day-Ahead Demand Reduction Distribution Amount

The Day-Ahead demand reduction distribution amount is an hourly charge to Asset Owners at each Settlement Location to recover the sum of the demand reduction payments made under Section 8.5.24 of this Attachment AE and is calculated as:

\[
\text{Day-Ahead Demand Reduction Distribution Amount} = (\text{Day-Ahead Demand Reduction Distribution Rate}) \times (\text{Day-Ahead Demand Reduction Distribution Quantity})
\]

1. The Day-Ahead Demand Reduction Distribution Rate is the sum of all demand reduction payments for the Hour as calculated under Section 8.5.24 of this Attachment AE multiplied by (-1), divided by the sum of all Asset Owners’ Day-Ahead Demand Reduction Distribution Quantities for all Settlement Locations for the Hour.

2. An Asset Owner’s Day-Ahead Demand Reduction Distribution Quantity at a Settlement Location for an hour is equal to that Asset Owner’s net cleared Energy withdrawals at that Settlement Location for that hour. An Asset Owner’s net cleared Energy withdrawal at a Settlement Location is calculated as the sum of the positive MWh value for the Asset Owner’s cleared Demand Bids, cleared Self-Charging MSR Offers, the positive MWh value for the Asset Owner’s net cleared Export and Import Interchange Transactions, the positive MWh value for the Asset Owner’s net cleared Virtual Energy Bids and Offers at that Settlement Location.

8.6.1 Real-Time Energy Amount

An RTBM payment or charge for Energy is calculated at each Settlement Location for each Asset Owner for each Dispatch Interval and hour as follows:

1. For Energy associated with loads, and Self-Charging MSRs:
(a) Real-Time Asset Energy Dispatch Interval Amount =
Real-Time LMP * \[((Real-Time Load Billing Meter Quantity) – (Day-Ahead Cleared Load Energy Quantity)) – (Real-Time Asset Energy Bilateral Settlement Schedules)] / 12

(i) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with that load, Self-Charging MSR, or station power from offline generation Settlement Location.

(ii) An Asset Owner’s Real-Time Load Billing Meter Quantity at that load Settlement Location is (i) the five (5) minute Reported Load submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12) or (ii) the hourly Reported Load profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data. The Transmission Provider shall make any necessary adjustments to the submitted Reported Load, as described under Section 8.6.1.1 of this Attachment AE.

(iii) An Asset Owner’s Day-Ahead Cleared Load Energy Quantity is the MW quantity associated with cleared Demand Bids and cleared Self-Charging MSR Offers at that load Settlement Location as described under Section 5.1.3 of this Attachment AE.

(iv) An Asset Owner’s Real-Time Asset Energy Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that load Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(b) Real-Time Asset Energy Hourly Amount =
Sum of Real-Time Asset Energy Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(2) For Energy associated with Resources:
(a) Real-Time Energy Dispatch Interval Amount =

(i) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with that Resource Settlement Location.

(ii) An Asset Owner’s Real-Time Resource Billing Meter Quantity at that Resource Settlement Location, excluding Self-Charging MSRs

is (i) the five (5) minute actual meter MWh Resource output quantity submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12) or (ii) the hourly actual meter MWh Resource output injection or withdrawal quantity profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data.

(iii) An Asset Owner’s Day-Ahead Cleared Resource Energy Hourly Quantity is the MW quantity associated with cleared Resource Offers, excluding Self-Charging MSRs at that Resource Settlement Location as described under Section 5.1.3 of this Attachment AE.

(iv) An Asset Owner’s Real-Time Asset Energy Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that Resource Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(b) Real-Time Energy Hourly Amount =

Sum of Real-Time Energy Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(3) For Energy associated with Interchange Transactions:

(a) Real-Time Non-Asset Energy Dispatch Interval Amount =

(i) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable External Interface Settlement Location.

(ii) An Asset Owner’s Real-Time Import Energy Quantity is the five (5) minute Dispatch Interval MW quantity scheduled for use in the RTBM, adjusted for curtailments, at that External Interface Settlement Location.

(iii) An Asset Owner’s Day-Ahead Import Energy Quantity is the five (5) minute Dispatch Interval MW quantity calculated by the Transmission Provider for each Dispatch Interval by multiplying the scheduled MW in the Dispatch Interval by the ratio of (a) hourly scheduled amount for use in the Day-Ahead Market and (b) the MW amount of cleared Import Interchange Transaction Offers, as described under Section 5.1.3 of this Attachment AE, at that External Interface Settlement Location.

(iv) An Asset Owner’s Real-Time Non-Asset Energy Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that External Interface Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(4) For Energy associated with Export Interchange Transactions:

(a) Real-Time Non-Asset Energy Dispatch Interval Amount = 

(i) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, associated with the applicable External Interface Settlement Location.

(ii) An Asset Owner’s Real-Time Export Energy Quantity is the five (5) minute Dispatch Interval MW quantity scheduled for use in the
RTBM, adjusted for curtailments, at that External Interface Settlement Location.

(iii) An Asset Owner’s Day-Ahead Export Energy Quantity is the five (5) minute Dispatch Interval MW quantity calculated by the Transmission Provider for each Dispatch Interval by multiplying the scheduled MW in the Dispatch Interval by the ratio of (a) hourly scheduled amount for use in the Day-Ahead Market and (b) the MW amount of cleared Export Interchange Transaction Bids, as described under Section 5.1.3 of this Attachment AE, at that External Interface Settlement Location.

(iv) An Asset Owner’s Real-Time Non-Asset Energy Bilateral Settlement Schedules are those Bilateral Settlement Schedules that settle at that External Interface Settlement Location as submitted in accordance with Section 8.2.1 of this Attachment AE.

(b) Real-Time Non-Asset Energy Hourly Amount = 
Sum of Real-Time Non-Asset Energy Dispatch Interval Amount over all Dispatch Intervals in the Hour.

(5) For Energy associated with remaining Bilateral Settlement Schedules:

Real-Time Non-Asset Energy Hourly Amount =
(Real-Ahead LMP) * [(Real-Time Non-Asset Energy Bilateral Settlement Schedules for Energy) * (-1)]

(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.

(b) An Asset Owner’s Real-Time Non-Asset Energy Hourly Bilateral Settlement Schedules for Energy are those Bilateral Settlement Schedules that settle at Settlement Locations other than External Interface Settlement Locations, that Asset Owner’s load Settlement Locations or that Asset Owner’s Resource Settlement Locations, as submitted in accordance with Section 8.2.1 of this Attachment AE.

(6) For Energy associated with Day-Ahead Market cleared Virtual Energy Bids:
Real-Time Virtual Energy Dispatch Interval Amount =
\[
[(\text{Real-Time LMP}) \times \left(\frac{\text{Day-Ahead Cleared Virtual Energy Bid Hourly Quantity}}{12}\right)] \times (-1)
\]
(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.
(b) An Asset Owner’s Day-Ahead Cleared Virtual Energy Bid Hourly Quantity is the MW quantity associated with cleared Virtual Energy Bids as described under Section 5.1.3 of this Attachment AE at that Settlement Location.

(7) For Energy associated with Day-Ahead Market cleared Virtual Energy Offers:
Real-Time Virtual Energy Dispatch Interval Amount =
\[
[(\text{Real-Time LMP}) \times \left(\frac{\text{Day-Ahead Cleared Virtual Energy Offer Hourly Quantity}}{12}\right)] \times (-1)
\]
(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, associated with the applicable Settlement Location.
(b) An Asset Owner’s Day-Ahead Cleared Virtual Energy Offer Hourly Quantity is the MW quantity associated with cleared Virtual Energy Offers as described under Section 5.1.3 of this Attachment AE at that Settlement Location.

8.6.5 Reliability Unit Commitment Make Whole Payment Amount

(1) Asset Owners of Resources committed by the Transmission Provider during the RUC processes, are eligible to receive a RUC make whole payment. Asset Owners of Resources committed by a local transmission operator during the RUC processes to address a Local Emergency Condition are eligible to receive a RUC make whole payment, except that, if the Market Monitor determines such Resources were selected in a discriminatory manner by the local transmission operator, as determined pursuant to Section 6.1.2.1 of this Attachment AE, and such Resources were affiliated with the local transmission operator, then such Resources are not eligible to receive a RUC make whole payment. A RUC make whole payment is
made to the Asset Owner when the sum of a Resource’s costs associated with actual
Energy and cleared RTBM Operating Reserve is greater than the RTBM revenues
received over the Resource’s RUC make whole payment eligibility period.
Recovery of such compensation shall be collected in accordance with Section 8.6.7
of this Attachment AE.

(2) A Resource’s RUC make whole payment eligibility period is equal to the set of a
Resource’s contiguous RUC Commitment Periods and adjacent Day-Ahead Market
commitment periods except;

(a) For Resources with a set of contiguous Day-Ahead and RUC Commitment
Periods that continue from one Operating Day to the next Operating Day, a
RUC make whole payment eligibility period is created for each Operating
Day in which there is a RUC commitment. A RUC make whole payment
eligibility period is created for each Operating Day with a RUC
commitment. The start of a RUC make whole payment eligibility period is
the later of (1) beginning of the Operating Day or (2) the beginning of the
set of contiguous Day-Ahead Market and RUC commitments. The end of a
RUC make whole payment eligibility period is the earlier of (1) the end of
the set of contiguous Day-Ahead Market and RUC commitments or (2) the
end of the Operating Day; or

(b) For an MCR that cleared in the Day-Ahead Market and was transitioned to
a different configuration in Real-Time by the Transmission Provider or by
a local transmission operator to address a Local Emergency Condition
(unless such transition instruction fails the discrimination and affiliation
screens set forth in Section 6.1.2.1 of this Attachment AE), the costs in the
intervals preceding the RUC commitment for the purpose of buying back
Operating Reserve products while the Resource transitions to the RUC
committed configuration, as defined by the Transition State Time of the
Resource’s offer parameters in Section 4.1(9) of this Attachment AE, are
included in the RUC make whole payment calculation.
The following cost recovery rules apply to each RUC make whole payment eligibility period. Resource production costs are calculated using the RTBM Offer prices in effect at the time the commitment decision was made for start-up, transitions, no-load, and minimum-energy; and the RTBM Offer price in effect at the solving of a dispatch interval for the Energy above minimum energy, Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve.

(a) If the Transmission Provider cancels a Commitment Instruction prior to the start of the associated RUC make whole payment eligibility period, the Asset Owner will receive reimbursement for a time-based pro-rata share of the Resource’s RTBM Start-Up Offer unless precluded by Section 8.6.5(3)(e)(i) of this Attachment AE. 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.

(b) In order to receive the full amount of Start-Up Offer recovery within a RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in at least one Dispatch Interval in the RUC make whole payment eligibility period.

(c) In order to receive recovery of No-Load Offer costs in any Dispatch Interval in the RUC make whole payment eligibility period, the Resource must be a Synchronized Resource in that Dispatch Interval.

(d) There may be more than one RUC make whole payment eligibility period for a Resource in a single Operating Day. A single RUC make whole payment eligibility period is contained within a single Operating Day.

(e) A Resource’s RUC commitment level offer costs include Start-Up Offer cost and Transition State Offer cost for a RUC make whole payment eligibility period in which that Resource is committed with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a), (b)
or (c) of this Attachment AE. The commitment level cost eligible for recovery is calculated by subtracting: (1) all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or (c) of this Attachment AE contained within a RUC make whole payment eligibility period and all RUC commitments that are associated with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE within a RUC make whole payment eligibility period; from (2) all eligible commitment level offer costs associated with the final Resource schedule in a RUC make whole payment eligibility period. The resulting difference can represent a charge or a payment and is considered as an adjustment when determining a RUC make whole payment.

(i) Except for an MCR that is committed by RUC in a different configuration than in the Day-Ahead Market, when a RUC make whole payment eligibility period is created after a Day-Ahead make whole payment eligibility period and is adjacent and preceding that Day-Ahead make whole payment eligibility period where the Day-Ahead Start-Up Offer Amount defined in Section 8.5.9(3)(b)(i) of this Attachment AE was considered, the Day-Ahead Start-up Offer Amount is used in place of the RUC Start-up costs.

(ii) In any RUC make whole payment eligibility period for which the RUC SCUC did not consider the Resource’s Start-Up Offer in the original commitment decision, except for commitments made as described under Sections 5.2.2(3), 6.1.2(3) and 6.1.2(4) of this Attachment AE, the Resource’s Start-Up Offer shall equal zero.

(iii) A Resource’s RTBM Start-Up costs are not eligible for recovery in the following RUC make whole payment eligibility periods:
Any RUC make whole payment eligibility period for which a Resource is a Synchronized Resource prior to this commitment period at a time one (1) hour prior to that Resource’s RUC Commit Time in addition to the Resource’s Sync-To-Min Time unless the RUC make whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the one (1) hour in addition to the Resource’s Sync-To-Min Time; or

For any RUC make whole payment eligibility period for which a Staggered Start Resource is a Synchronized Resource prior to this commitment period at a time two (2) hours prior to that Resource’s RUC Commit Time in addition to the Resource’s Sync-To-Min Time unless the RUC market whole payment eligibility period is following a Day-Ahead Market or RUC make whole payment eligibility period that ends within the two (2) hours in addition to the Resource’s Sync-To-Min Time.

When there is a cost transferred from the Day-Ahead Market make whole payment as described in Section 8.5.9(3)(b)(iii) of this Attachment AE, the commitment level cost in the RUC make whole payment is increased by the amount allocated to the RUC make whole payment as described in Section 8.5.9(3)(b)(iii) of this Attachment AE.

In any RUC make whole payment eligibility period for which the RUC SCUC considered the Resource’s Transition State Offer in the original commitment decision, or the RTBM Transition State Offer is associated with a manual commitment as described under Sections 5.2.2(3), 6.1.2(3) and 6.1.2(4) of this Attachment AE, the
Transition State Offer cost is eligible for recovery when the following conditions are met:

(1) In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target “from” configuration and the Resource must be a Synchronized Resource; and

(2) In at least one Dispatch Interval during the scheduled configuration period, the Resource is in the target “to” configuration and the Resource must be a Synchronized Resource.

(vi) If the Transmission Provider cancels a transition between configurations prior to the scheduled transition associated with a RUC make whole payment eligibility period, the Asset Owner will be eligible to recover a time-based pro-rata share of the Resource’s RTBM Transition State Offer through the RUC make whole payment unless precluded by Section 8.6.5(3)(e)(i) of this Attachment AE. 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.

(vii) When a Resource loses eligibility to recover a Start-Up Offer cost for the reason described in Section 8.6.5(3)(e)(iii)(1) of this Attachment AE, or loses eligibility to recover Transition State Offer costs for the reason described in Section 8.6.5(3)(v) of this Attachment AE, to prevent overstating avoided costs, the commitment level cost is adjusted by the lesser of: (1) its Start-Up Offer cost and Transition State Offer cost associated with commitments that have a RTBM Resource Offer commitment status
as defined under Section 4.1(10)(a) of this Attachment AE; or (2) the ineligible RTBM Start-Up Offer cost plus the ineligible Transition State Offer costs.

(viii) For each RUC make whole payment eligibility period within an Operating Day, a Resource’s eligible Start-Up cost is divided by the lesser of (1) the hours of RUC commitment within the Resource’s applicable Minimum Run Time multiplied by twelve (12), rounded down to the nearest whole interval, or (2) twenty-four (24) hours multiplied by twelve (12), to achieve a Dispatch Interval proration for the purpose of allocating Start-Up costs across adjacent Day-Ahead Market or RUC make whole payment eligibility periods.

(3) If the number of participating Dispatch Interval meets or exceeds the duration of the divisor as described in (viii) above, the full cost of the Start-Up Offer is included in the commitment level cost for the RUC make whole payment eligibility period.

(4) If the number of participating Dispatch Intervals is less than the duration of the divisor as described in (viii) above, the proration is multiplied by the number of participating Dispatch Intervals to achieve a single Start-Up Offer amount to be included in the commitment level cost for that RUC make whole payment eligibility period. Any remaining eligible RUC Start-Up cost will be included in the commitment level cost for the following and adjacent Day-Ahead Market make whole payment eligibility period as described in Section 8.6.5(3)(f) of this Attachment AE or the following and adjacent RUC make whole payment eligibility period in the next Operating Day.

(f) If the Resource has been committed in the Day-Ahead Market in a period adjacent to and following a RUC make whole payment eligibility period to
the extent that the full amount of the eligible RTBM Start-Up cost is not accounted for in the RUC make whole payment eligibility period, any remaining eligible RTBM Start-Up cost is carried forward for recovery in the Day-Ahead make whole payment eligibility period.

(g) If a Resource has operated outside of its Operating Tolerance in any Dispatch Interval, any cost associated with energy output-injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(h) If a Resource becomes non-dispatchable in any Dispatch Interval, any cost associated with energy output-injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(i) If a Resource’s minimum operating limit is increased above the Resource’s minimum operating limit that was used to make the commitment decision, the increase is greater than the Resource’s Operating Tolerance and the Resource remains dispatchable in any Dispatch Interval, any cost associated with energy output-injection or withdrawal above the Resource’s economic operating point is not eligible for recovery for that Dispatch Interval where such cost is calculated as described under Section 8.6.5(4)(d) of this Attachment AE.

(j) If a Resource’s self-commitment period is less than the Resource’s Minimum Run Time, the Transmission Provider will relax the Resource’s Minimum Run Time to equal the self-commit period.

(k) If a Resource is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) of this Attachment AE in the RTBM, the Resource will be eligible to recover applicable recurring costs as defined in Section 8.6.5(4)(b) of this Attachment AE for that period in the RUC make whole payment eligibility period.
(I) For an MCR, additional costs of revenues incurred when the Resource has cleared Operating Reserve in the Day-Ahead Market and must buy back that position in Real-Time will be considered as an adjustment when determining a RUC make whole payment. These costs or revenues must be incurred during time periods in which the Resource is ineligible to clear Operating Reserve products due to transitioning between configurations in Real-Time where at least one configuration is the result of a RUC commitment, and the transition is not forced by the Resource Offer. The Market Participant may also be eligible to recover Operating Resource product buy back costs or revenue incurred during a Real-Time transition is the Resource is transitioned by a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE), then such Resources are not eligible to recover any costs or revenues associated with the transition as part of a RUC make whole payment. In such cases, the adjustment is equal to the sum of the cleared Day-Ahead Market Operating Reserve revenue as calculated from the Day-Ahead Operating Reserve MCP and the cleared incremental RTBM Operating Reserve revenue as calculated from the RTBM Operating Reserve MCPs. For Contingency Reserve, the adjustment is limited to the time period defined as the transition State Time submitted in the Resource Offer. For Regulation-Up and/or Regulation-Down, the adjustment is limited to all Dispatch Intervals within the transition hour.

(4) The payment to each Asset Owner for each eligible Settlement Location for a given RUC make whole payment eligibility period is calculated as follows:

\[
\text{RUC Make Whole Payment Amount} = \begin{cases} 
0, & \text{if either zero or if} \\
\text{Maximum of} \left[ \text{Either Zero or} (\text{RUC Make Whole Payment Commitment Cost Amount} + \text{RUC Make Whole Payment Cost Amount in the RUC Make Whole Payment Eligibility Period} + \text{RUC Make Whole Payment Revenue Amount in the RUC Make Whole Payment Eligibility Period} - \text{Uninstructed Resource Deviation} \right], & \text{otherwise}
\end{cases}
\]

(a) An Asset Owner’s Real-Time Make Whole Payment Commitment Cost Amount for each eligible Resource in the RUC make whole payment eligibility period is equal to:

(i) Start-Up Offer used to make the commitment decision which was committed by the Transmission Provider or by a local transmission operator to address a Local Emergency Condition (unless such commitment instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE); plus

(ii) The Transition State Offer used to make the transition decision for an MCR that cleared in the Day-Ahead Market or committed by the RUC process that were transitioned by the Transmission Provider into a different configuration in Real-Time or transitioned by a local transmission operator to address a Local Emergency Condition (unless such transition instruction fails the discrimination and affiliation screens set forth in Section 6.1.2.1 of this Attachment AE); plus

(iii) Real-Time Cancelled Transition Amount as described in Section 8.6.5(3)(e)(vi) of this Attachment AE; plus

(iv) Amount of shared Start-Up costs between Day-Ahead Market and RUC make whole payment eligibility periods as described in Section 8.5.9(3)(b)(iii) of this Attachment AE; plus

(v) Amount of costs where the Resource loses eligibility to recover as describe in Section 8.6.5(3)(e)(vii) of this Attachment AE, minus

(vi) The sum of all Start-Up Offer cost and Transition State Offer cost associated with the schedule created by combining (1) all Day-Ahead Market commitments with a Day-Ahead Market Resource Offer commitment status as defined under Section 4.1(10)(a), (b) or
(c) of this Attachment AE contained within a RUC make whole payment eligibility period and (2) all RUC commitments that are associated with a RTBM Resource Offer commitment status as defined under Section 4.1(10)(a) of this Attachment AE within a RUC make whole payment eligibility period.

(b) An Asset Owner’s RUC Make Whole Payment Cost Amount for each eligible Resource is equal to the sum for all Dispatch Intervals in the RUC commitment of:

(i) No-Load Offer used to make the RUC commitment decision, less any Day-Ahead Market No-Load from an MCR resulting from a different Day-Ahead Market committed configuration;

(ii) Energy cost at minimum output injection or withdrawal as calculated from the Energy Offer Curve used to make the commitment decision;

(iii) Energy cost above minimum output injection or withdrawal as calculated from the Energy Offer Curve that applied to the current Dispatch Interval;

(iv) For MCRs, the Energy cost shall be calculated from the Energy Offer Curve used in the Day-Ahead Market from zero to the lesser of (1) Day-Ahead Market cleared Energy or (2) the submitted meter in Real-Time, multiplied by (-1);

(v) For Resources (other than MCRs cleared in the Day-Ahead Market that were committed into a different configuration in Real-Time), Operating Reserve cost, including the impact from product substitution as described under Section 5.1.2(2)(c) of this Attachment AE, associated with cleared Real-Time Operating Reserve. Excess Regulation-Up Mileage and Excess Regulation-Down Mileage as calculated from the Operating Reserve Offers, except when those costs are associated with self-scheduled Operating Reserve which is greater than or equal to the amount of
(vi) For an MCR that was cleared in the Day-Ahead Market and was committed into a different configuration in Real-Time and is not transitioning into that configuration, the Operating Reserve cost, including the impact from product substitution as described under Section 5.1.2(2)(c) of the Attachment AE, associated with cleared Real-Time Operating Reserve minus Day-Ahead Operating Reserve cost, including the impact from product substitution as described under Section 5.1.2(2)(c) of this Attachment AE, associated with the lesser of (1) cleared Real-Time Operating Reserve or (2) cleared Day-Ahead Operating Reserve, except when self-scheduled Operating Reserve is less than or equal to the amount of Real-Time Operating Reserve cleared then the Operating Reserve cost shall be set equal to zero;

(vii) Real-Time Potential Regulation-Up Unused Mileage Make Whole Payment as calculated under Section 8.6.19(2)(b) of this Attachment AE; and

(viii) Real-Time Potential Regulation-Down Unused Mileage Make Whole Payment as calculated under Section 8.6.20(2)(b) of this Attachment AE.

(c) An Asset Owner’s RUC Make Whole Payment Revenue Amount for each eligible Resource that is committed by the Transmission Provider as specified in Section 4.1(10)(b) and (c) is equal to the sum of the following for all Dispatch Intervals in the RUC commitment:

(i) Dispatch Interval revenue associated with Energy calculated by multiplying actual Dispatch Interval Energy output injection or withdrawal by Real-Time LMP, except for MCRs that cleared in the Day-Ahead Market and were transitioned into a different configuration in Real-Time, in which case such revenue is
calculated by multiplying Real-Time LMP by the incremental increase of the actual Dispatch Interval Energy output injection or withdrawal above the Day-Ahead cleared Energy;

(ii) the sum of the revenues calculated under Sections 8.6.3 and 8.6.4 of this Attachment AE for that eligible Resource;

(iii) Energy revenue associated with payments made under Section 8.6.6 of this Attachment AE;

(iv) amounts associated with settlement made under Section 8.6.15 of this Attachment AE;

(v) Real-Time Unused Regulation-Up Mileage Make Whole Payment as calculated under Section 8.6.19(2) of this Attachment AE;

(vi) Real-Time Unused Regulation-Down Mileage Make Whole Payment as calculated under Section 8.6.20(2) of this Attachment AE;

(vii) Real-Time Regulation-Up Service Revenue as calculated under Section 8.6.19(2)(a)(i) of this Attachment AE;

(viii) Real-Time Regulation-Down Service Revenue as calculated under Section 8.6.20(2)(a)(i) of this Attachment AE;

(ix) Excess Regulation-Up Mileage Dispatch Interval Amount as calculated under Section 8.6.2(1)(a)(v) of this Attachment AE, multiplied by (-1), and

(x) Excess Regulation-Down Mileage Dispatch Interval Amount as calculated under Section 8.6.2(2)(a)(v) of this Attachment AE, multiplied by (-1).

(d) An Asset Owner’s Uninstructed Resource Deviation Cost Disallowance, Non-Dispatchable Cost Disallowance, or Minimum Limit Cost Disallowance is equal to the positive difference between the Resource’s Energy cost at actual output injection or withdrawal as calculated from the Resource’s current Dispatch Interval Energy Offer Curve and the Resource’s Energy cost at the Resource’s economic operating point as
calculated from the Resource’s current Dispatch Interval Energy Offer Curve.

(e) A Resource’s economic operating point is the MW output injection or withdrawal where the cost on the Resource’s current Dispatch Interval Energy Offer Curve first exceeds the Real-Time LMP for that Resource.

(f) For MCRs that have been transitioned into a different configuration in Real-Time and are transitioning into that configuration, the Real-Time Combined Cycle Operating Reserve Adjustment Amount shall be equal to the sum of the cleared Day-Ahead Market Operating Reserve revenue as calculated from the Day-Ahead Operating Reserve MCP and the cleared incremental RTBM Operating Reserve revenue as calculated from the RTBM Operating Reserve MCPs.
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 above the Resource’s economic operating point and the Energy Offer Curve cost associated with the Resource’s additional output injection or withdrawal attributable to its response (“OOME MW”) is greater than the RTBM LMP, the Asset Owner will receive a payment for the difference multiplied by the OOME MW. The payment shall be limited to the amount necessary to compensate the Asset Owner for any under-recovery resulting from the Resource’s response to the OOME. The OOME MW is calculated as the positive difference between (i) the lesser of the actual Resource output injection or withdrawal or the Resource’s economic operating point 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 below the Resource’s economic operating point (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 or increased withdrawal attributable to its response (“OOME MW”). 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 injection or withdrawal or (ii) the Resource’s OOME 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.
8.6.7 Reliability Unit Commitment Make Whole Payment Distribution Amount

An RTBM system-wide and local charge will be calculated at each Settlement Location for each Asset Owner for each hour in order to fund the payments made under Section 8.6.5 and payments made under Section 8.5.9 of this Attachment AE to Resources committed to address a Local Reliability Issue or Local Emergency Condition. The system-wide amount will be determined by multiplying an Asset Owner’s system-wide distribution volume by a daily system-wide RUC make whole payment rate as described in Section 8.6.7(A) of this Attachment AE. The local amount for each Local Settlement Area impacted by a Local Reliability Issue will be determined by multiplying an Asset Owner’s Local Settlement Area distribution volume by the Local Settlement Area Make Whole Payment Distribution Rate as described in Section 8.6.7(B) of this Attachment AE.

A. The RUC System-Wide Make Whole Payment Distribution Amount shall be calculated as follows:

The RUC System-Wide Make Whole Payment Distribution Amount =
[(RUC System-Wide Make Whole Payment Distribution Rate) *
(RUC System-Wide Make Whole Payment Distribution Volume)]

(1) The RUC System-Wide Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day as calculated under Section 8.6.5 excluding make whole payments made to Resources committed to address a Local Reliability Issue by the Transmission Provider at the request of a local transmission operator or committed by a local transmission operator to address a Local Emergency Condition, divided by the sum of Asset Owners’ RUC System-Wide Make Whole Payment Distribution Volumes for all Settlement Locations for the entire Operating Day.

(2) An Asset Owner’s RUC System-Wide Make Whole Payment Distribution Volume at a Settlement Location for an hour is equal to the sum of following values that are calculated for each Dispatch Interval within the hour:
(a) The absolute value of the sum of actual Real-Time Settlement Location deviations from Day-Ahead Market cleared amounts for load, cleared Self-Charging MSR Offers, virtual offer transactions and interchange transactions except that, during any Dispatch Interval in which the Transmission Provider has declared an Emergency Condition due to a capacity shortage, Real-Time actual load deviations from Day-Ahead Market cleared amounts shall be limited to deviations associated with actual Real-Time load and actual Real-Time Self-Charging MSRs in excess of amounts cleared in the Day-Ahead Market;

(b) For Resources cleared in the Day-Ahead Market, except MCRs with an RTBM Resource Offer commitment status as defined under Section 4.1(10)(b) or (c) of this Attachment AE, that have been transitioned in Real-Time by the Transmission Provider or local transmission operator into a Real-Time configuration with a higher applicable minimum capacity operating limit than the Day-Ahead Market committed configuration, (a) the positive difference between the RTBM Resource applicable minimum limits and Day-Ahead Market Resource cleared Energy quantity; or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1) the RTBM Resource regulation minimum limit and (2) the greater of the Day-Ahead Market Resource cleared Energy quantity or the Resource’s Day-Ahead Market regulation minimum limit, provided that:

(i) The applicable RTBM Resource minimum limit is greater than the comparable Day-Ahead Market Resource minimum limit by more than the Resource’s Operating Tolerance; and

(ii) The applicable RTBM Resource minimum limit is greater than the Day-Ahead Market cleared Energy amount; and
(iii) The Resource received a Dispatch Instruction less than or equal to the RTBM applicable minimum limit for at least one Dispatch Interval in the hour.

(c) For Resources cleared in the Day-Ahead Market, except combined cycle Resources with an RTBM Resource Offer commitment status as defined under Section 4.1(10)(b) or (c) of this Attachment AE that have been transitioned in Real-Time by the Transmission Provider or local transmission operator into a Real-Time configuration with a lower applicable maximum capacity operating limit than the Day-Ahead Market committed configuration, (a) the positive difference between the Resource Day-Ahead Market cleared Energy quantity and the RTBM Resource applicable maximum limit or (b) if the Resource has cleared regulation in the RTBM and has not cleared regulation in the Day-Ahead Market, the positive difference between (1) the lesser of the Resource’s RTBM regulation maximum limit or the Resource’s Day-Ahead Market Resource cleared Energy quantity and (2) the Resource’s RTBM regulation maximum limit, provided that:

(i) The applicable RTBM Resource maximum limit is less than the comparable Resource maximum limit submitted for use in the Day-Ahead Market by more than the Resource’s Operating Tolerance; and

(ii) The applicable RTBM Resource maximum limit is less than the Day-Ahead Market cleared Energy amount; and

(iii) The Resource received a Dispatch Instruction greater than or equal to the RTBM applicable maximum limit for at least one Dispatch Interval in the hour.

(d) For Resources cleared in the Day-Ahead Market, the Resource’s Day-Ahead Market cleared amount if that Resource is off-line in the
RTBM and if the Resource has not been de-committed or dispatched to zero by the Transmission Provider;

(e) For Resources that cleared in the Day-Ahead Market that are not able to follow Dispatch Instructions, including an MCR that is not in its committed configuration, the absolute value of the difference between a Resource’s actual output injection or withdrawal and the Resource’s economic operating point. The Resource’s economic operating point is calculated as described under Section 8.6.5(4)(e) of this Attachment AE;

(f) For Resources that were not offered in the Day-Ahead Market and that self-committed following the close of the Day-Ahead Market, and for Resources that were offered and not cleared in the Day-Ahead Market and that self-committed following the close of the Day-Ahead RUC, the actual Resource output injection or withdrawal if the Resource received a Dispatch Instruction with an absolute value less than or equal to the RTBM applicable minimum charge or discharge limit for at least one Dispatch Interval in the hour;

(g) A Resource’s economic operating point, as calculated as described under Section 8.6.5(4)(e) of this Attachment AE, for Resource or MCR configuration that was committed following the close of the Day-Ahead Market if that Resource is off-line in the RTBM and that Resource was not de-committed by the Transmission Provider including, for an MCR, the amount of the incremental MWs from Day-Ahead Market cleared Energy to Real-Time economic operating point; and

(h) The absolute value of a Resource’s URD if that Resource operated outside of its Operating Tolerance and the Resource has not been exempted from URD as described under Section 6.4.1.1 of this Attachment AE.
B. Local Settlement Area Make Whole Payment Distribution Amount shall be calculated as follows:

Local Settlement Area Make Whole Payment Distribution Amount =

\[\text{[(Local Settlement Area Make Whole Payment Distribution Rate) } \times \text{ (Local Settlement Area Make Whole Payment Distribution Volume)]}\]

(1) The Local Settlement Area Make Whole Payment Distribution Rate is the sum of all make whole payments for the Operating Day for a Local Settlement Area as calculated under Sections 8.6.5, 8.6.6, and 8.5.9 of this Attachment AE for Resources committed by the Transmission Provider at the request of a local transmission operator or by a local transmission operator to address a Local Reliability Issue in the Local Settlement Area, divided by the sum of Asset Owners’ Local Settlement Area Make Whole Payment Distribution Volumes within the impacted Local Settlement Area for the entire Operating Day.

(2) An Asset Owner’s Local Settlement Area Make Whole Payment Distribution Volume for the impacted Local Settlement Area for an hour is equal to that Asset Owner’s Reported Load and Self-Charging MSRs in that Local Settlement Area for that hour.

8.6.15 Real-Time Regulation Service Deployment Adjustment Amount

A Real-Time regulation deployment adjustment amount charge or payment will be calculated for each Asset Owner for each Dispatch Interval when a Resource with cleared Real-Time Regulation-Up Service and/or Regulation-Down Service is deployed. The amount will be determined as one-twelfth of the sum of:

(1) For Regulation-Up Service deployment, the amount is equal to the difference between (1) actual Regulation-Up Service deployment MW multiplied by Real-Time LMP at that Resource Settlement Location; and (2) Lesser of (i) as-dispatched Energy Offer Curve cost of actual Regulation-Up Service deployment MW, and (ii) Mitigated Energy Offer Curve cost of actual Regulation-Up Service deployment MW.
The actual Regulation-Up Service deployment MW is calculated as the difference between the lesser of (1) Dispatch Instruction plus the average Regulation-Up Service deployment or (2) \textit{Absolute value of actual} Resource output, and the Resource’s average Dispatch Instruction for Energy. If the absolute value of the Resource’s actual output is less than or equal to the \textit{absolute value of the} Resource’s average Dispatch Instruction for Energy, then the actual Regulation-Up Service deployment MW is equal to zero (0).

For Regulation-Down Service deployment, the amount is equal to the difference between (1) Greater of (i) as-dispatched Energy Offer Curve cost of actual Regulation-Down Service deployment MW, and (ii) Mitigated Energy Offer Curve cost of actual Regulation-Down Service deployment MW; and (2) actual Regulation-Down Service deployment MW multiplied by RTBM LMP.

The actual Regulation-Down Service deployment MW is calculated as the difference between the Resource’s average Dispatch Instruction for Energy and the greater of (1) Average Dispatch Instruction minus the average Regulation-Down Service deployment or (2) \textit{Absolute value of actual} Resource output. If the absolute value of the Resource’s actual output is greater than or equal to the \textit{absolute value of the} Resource’s average Dispatch Instruction for Energy, then the actual Regulation-Down Service deployment MW is equal to zero (0).

Distribution of such charges and recovery of such payments shall be made in accordance with Section 8.8 of this Attachment AE.
8.6.16 Over-Collected Losses Distribution Amount

The MLC of the Day-Ahead Market LMP and RTBM LMP creates an over collection of funds (or under collection of funds as a result of the Real-Time deviation accounting) related to the payment for losses (“Over-Collected Losses”) that must be refunded (or charged) as described below. Over-Collected Losses refunds associated with a GFA Carve Out and FSE are calculated pursuant to this Section 8.6.16 and included as a credit to the GFA Carve Out costs and FSE costs under Section 8.5.18 of this Attachment AE. Over-Collected Losses refunds associated with a GFA Carve Out shall not be credited to a GFA Carve Out Responsible Entity to the extent of load it serves under GFA Carve Out Schedule(s). Over-Collected Losses refunds associated with a FSE shall not be credited to Western-UGP for the amount of load served under an FSE Schedule(s).

1) A payment or charge for the portion of such Over-Collected Losses allocable to each Asset Owner (“Over-Collected Losses Distribution Amount”) shall be calculated for each hour at each Settlement Location for which an Asset Owner has a net RTBM Energy withdrawal within a Loss Pool and such Loss Pool contributed positively to the Over-Collected Losses or were charged for Real-Time pseudo-tie losses at the Settlement Location of the sink of the pseudo-tie path for use of the SPP Transmission System according to the following calculations:

(a) Each Loss Pool’s contribution to the Over-Collected Losses is calculated based on transactional activity in that Loss Pool where such transactional activity shall include: actual Resource Energy, actual load consumption, and actual Real-Time Self-Charging MSRs, RTBM Import Interchange Transactions and RTBM Export Interchange Transactions.

(b) A “Real-Time Loss Pool loss rebate factor” is calculated hourly for each Loss Pool. The Real-Time Loss Pool loss rebate factor is equal to the sum of the positive loss rebate factors calculated in the RTBM at each withdrawal Settlement Location in the Loss Pool (the “Real-Time Withdrawal Settlement Location loss rebate factor”). Real-Time Withdrawal Settlement Location loss rebate factors are calculated hourly as
the sum of i) the difference between the Real-Time MLC at a withdrawal Settlement Location in the Loss Pool and the injection weighted average Real-Time MLC for the Loss Pool, multiplied by the withdrawal quantity at that withdrawal Settlement Location and ii) the sum of charges for Real-Time pseudo-tie losses at the Settlement Location of the sink of the pseudo-tie path.

(i) For any Settlement Location that is contained within more than one Settlement Area Loss Pool, any injections or withdrawals associated with such Settlement Location shall be allocated pro rata to the applicable Settlement Area Loss Pools based upon actual submitted real-time meter values for the Meter Data Submittal Locations contained within each applicable Settlement Area Loss Pool.

(ii) The total withdrawal quantity at a Settlement Location is calculated as the positive value of the sum of: (1) actual Resource output injection or withdrawal; (2) actual load consumption, and actual Real-Time Self-Charging MSRs; (3) RTBM scheduled Import Interchange Transactions; and (4) RTBM scheduled Export Interchange Transactions at that Settlement Location.

(c) The injection weighted average Real-Time MLC for a Loss Pool is calculated assuming that net RTBM injection in a Loss Pool first serves net RTBM withdrawals in the Loss Pool and then goes to meet the net RTBM withdrawal in Loss Pools that do not have sufficient Net RTBM injections to meet all net RTBM withdrawals.

(d) A Real-Time Loss Pool Unitized Loss Rebate Factor is calculated for each Loss Pool and is equal to that Real-Time Loss Pool loss rebate factor, as calculated in subsection (1)(b) above, divided by the sum of all Real-Time Loss Pool loss rebate factors.

(2) An Over-Collected Losses Distribution Amount shall be calculated hourly for each Asset Owner for each Loss Pool and withdrawal Settlement Location within each Loss Pool as follows:
Asset Owner Settlement Location Over-Collected Losses Distribution Amount = 

(a) The Real-Time Over-Collected Losses Amount in an hour is equal to the sum for all Settlement Locations of [(Real-Time LMP – Real-Time MCC)] * the difference between actual Energy and Day-Ahead Market cleared Energy MW at each Settlement Location plus the sum of the losses for all Resources or loads that are pseudo-tied out of the SPP Balancing Authority.

(b) The Day-Ahead Over-Collected Losses Amount in an hour is equal to the sum for all Settlement Locations of an amount equal to [(Day-Ahead LMP – Day-Ahead MCC)] * Total cleared Day-Ahead Market Energy MW at each Settlement Location.

(c) The Asset Owner Settlement Location Withdrawal in Loss Pool is equal to the positive value of the sum for that Asset Owner at that Settlement Location in that Loss Pool of: (i) actual Resource output/injection or withdrawal; (ii) actual load consumption, and actual Real-Time Self-Charging MSRs; (iii) RTBM scheduled Import Interchange Transactions; (iv) RTBM scheduled Export Interchange Transactions; (v) RTBM Bilateral Settlement Schedules where the buyer is the Asset Owner of the net withdrawal at that Settlement Location, capped at the actual withdrawal, adjusted by Sections 8.6.16(2)(c)(vii) and 8.6.16(2)(c)(viii) of this Attachment AE, as described in the Market Protocols; (vi) Day-Ahead Market Bilateral Settlement Schedules where the buyer is the Asset Owner of the net withdrawal at that Settlement Location, capped at the actual withdrawal, adjusted by Sections 8.6.16(2)(c)(vii) and 8.6.16(2)(c)(viii) of this Attachment AE, as described in the Market Protocols; (vii) GFA Carve Out Schedules; and (viii) FSE Schedules.
(d) Real-Time Loss Pool Unitized Loss Rebate Factor is the factor calculated as described in subsection (1)(d) above.

8.6.22 Real-Time Demand Reduction Distribution Amount

The Real-Time demand reduction distribution amount is an hourly payment or charge to Asset Owners at each Settlement Location to account for the sum of the demand reduction amounts calculated under Section 8.6.21 of this Attachment AE and is calculated as:

Real-Time Demand Reduction Distribution Amount = (Real-Time Demand Reduction Distribution Rate) * (Real-Time Demand Reduction Distribution Quantity)

(1) Real-Time Demand Reduction Distribution Rate is the sum of all demand reduction payments for the Hour as calculated under Section 8.6.21 of this Attachment AE multiplied by (-1), divided by the sum of all Asset Owner’s Real-Time Demand Reduction Distribution Quantities for all Settlement Locations for the hour.

(2) An Asset Owner’s Real-Time Demand Reduction Distribution Quantity for an hour is equal to that Asset Owner’s net actual Energy withdrawals at that Settlement Location for that hour. The net actual Energy withdrawal at a Settlement Location is calculated as the sum of an Asset Owner’s net actual-load consumption and the Energy withdrawal Real-Time Self-Charging MSRs at a Settlement Location is calculated as the sum of the positive MWh value for the Asset Owner’s metered withdrawals and the positive MWh value for the Asset Owner’s net Export and Import Interchange Transactions at that Settlement Location.
ATTACHMENT AF - MARKET POWER MITIGATION PLAN

3.2 Mitigation Measures for Energy Offer Curves

Mitigated Energy Offer Curves shall be submitted on a daily basis by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. For Multi-Configuration Resources ("MCR"), as defined in Attachment AE, for which a single configuration allows physical units to be swapped (e.g., Combustion Turbine 2 for Combustion Turbine 1), the costs used in the mitigated offer development for that configuration shall be those of the least cost physical unit that is available and can be swapped in such configuration. The mitigated Energy Offer Curve may be updated up to the close of the Day-Ahead Market as defined in Section 5.1 of Attachment AE of this Tariff for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Energy Offer Curve may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Energy Offer Curve submitted as of the close of the Day-Ahead Market will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day unless an exception is allowed in Section 3.2.E of this Attachment AF; for all other Resources the mitigated Energy Offer Curve submitted at the time the Day-Ahead RUC begins will apply to the Day-Ahead RUC on the day before the Operating Day, and the Intra-Day RUC processes and the RTBM on the Operating Day.

A. The Energy Offer Curve conduct thresholds are as follows:

(1) For Resources committed to address a Local Reliability Issue, the conduct threshold is a 10% increase above the mitigated Energy Offer Curve;

(2) For Resources located in a Frequently Constrained Area and not subject to Section 3.2(A)(1), the conduct threshold is a 17.5% increase above the mitigated Energy Offer Curve;

(3) For all other Resources the conduct threshold is a 25% increase above the mitigated Energy Offer Curve.
B. The Transmission Provider shall apply mitigation measures by replacing the Energy Offer Curve with the mitigated Energy Offer Curve if:

1. The Resource’s Energy Offer Curve exceeds the mitigated Energy Offer Curve by the applicable conduct threshold; and

2. The Resource has local market power as determined in Section 3.1; and

3. The Resource either:
   a. Fails the Market Impact Test as described in Section 3.7, or
   b. Is manually committed by the Transmission Provider or by a local transmission operator.

An Energy Offer below $25/MWh will not be subject to mitigation measures for economic withholding.

C. The mitigated energy offer shall be the Resource’s short-run marginal cost of producing energy as determined by the unit’s heat rate or similar production efficiency ratio; fuel costs and the costs related to fuel usage, such as transportation and emissions costs (“total fuel related costs”); and Energy Offer Curve (“EOC”) variable operations and maintenance costs (“VOM”) as detailed in the Market Protocols.

D. For Resources that are not ESRs, opportunity cost shall be an estimate of the Energy and Operating Reserve Markets revenues net of short run marginal costs for the marginal forgone run time during the timeframe when the Resource experiences the run-time restrictions as detailed in the Market Protocols. The run-time restrictions shall be updated as specified in the Market Protocols, with more frequent updating to occur the fewer hours that remain available, consistent with the Market Protocols. The Market Participant may include in the calculation of its mitigated Energy Offer Curve an amount reflecting the resource-specific opportunity costs expected to be incurred under the following circumstances:

1. Externally imposed environmental run-hour restrictions; or
(2) Physical equipment limitations on the number of starts or run-hours, as verified by the Market Monitoring Unit and determined by reference to the manufacturer’s recommendation or bulletin, or a documented restriction imposed by the applicable insurance carrier; or

(3) Fuel Supply Limitations.

Resource specific opportunity costs are calculated by forecasting Locational Marginal Prices based on futures contract prices for natural gas and the historical relationship between the SPP system marginal Energy component of LMP and the price of natural gas, as determined by the SPP Market Monitoring Unit. The formulas and instructions in the price forecast model shall be determined by the SPP Market Monitoring Unit and published in the Market Protocols as part of the Mitigated Offer Development Guidelines, updated, as needed, by the SPP Market Monitoring Unit. Such forecasts of LMPs shall take into account historical variability, and basis differentials affecting the Settlement Location at which the Resource is located for the three-year period immediately preceding the period of time in which the Resource is bound by the referenced restrictions, and shall subtract therefrom the forecasted costs to generate energy at the Settlement Location at which the Resource is located, as specified in more detail in Appendix G of the Market Protocols. If the difference between the forecasted Locational Marginal Prices and forecasted costs to generate energy is negative, the resulting opportunity cost shall be zero. The Market Monitoring Unit will verify all Market Participants’ opportunity cost calculations for consistency and accuracy. When the Market Monitoring Unit determines that the market price for any period was not competitive, it will adjust the LMP forecasting process used in the opportunity cost calculations to ensure that forecasted LMPs do not reflect non-competitive market conditions.
The following formula shall apply to all mitigated Energy Offer Curves unless specified otherwise in this section 3.2.D of this Attachment AF:

Mitigated Energy Offer ($/MWh) = HeatRate (mmBtu/MWh) * Performance Factor * Total Fuel Related Costs ($/mmBtu) + EOC VOM ($/MWh) + Opportunity Costs ($/MWh)

The Market Participant shall submit heat rate curves, descriptions of how spot fuel prices and/or contract prices are used to calculate fuel costs, variable fuel transportation and handling costs, emissions costs, and VOM to the Market Monitoring Unit. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. The information will be sufficient for replication of the mitigated Energy Offer Curve and shall include, among other data, the following information:

1. For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

2. For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

3. For VOM costs, Market Participants shall submit VOM costs, calculated in adherence with the Appendix G of the Market Protocols, reflecting short-run marginal costs, exclusive of fixed costs.

Further details associated with the development, validation, and updating of these costs are included in Appendix G of the Market Protocols.
For Demand Response Resources utilizing Behind-The-Meter Generation, the mitigated Energy Offer Curve shall be developed in the same manner as any other generating Resource as described above. For Demand Response Resources utilizing load reduction, the mitigated Energy Offer Curve shall reflect the quantifiable opportunity costs associated with the reduction, net of related offsetting increases in usage.

For Dispatchable Variable Energy Resources, the mitigated Energy Offer Curve may include, but shall not exceed, any quantifiable costs that vary by MWh output, including short-run incremental VOM. Mitigation will not apply to Non-Dispatchable Variable Energy Resources in the Real-Time Balancing Market; monitoring of Energy Offers for Non-Dispatchable Variable Energy Resources will occur.

For an ESR, the mitigated Energy Offer Curve may include, but shall not exceed, (i) charging cost and (ii) opportunity cost, both adjusted for round-trip efficiency. Charging cost is the cost at which the ESR charged, and opportunity cost is the average profit in the next hour forgone by charging or discharging in the current hour. The sum of the charging cost and opportunity cost is the average LMP that is expected for the next Operating Hour. This expected average LMP for the next Operating Hour is the unweighted average of the LMPs for the most recent 45 days comparing like Operating Hours. The mitigated Energy Offer Curve for MSRs shall have at least two breakpoints: one for charging and another for discharging. More breakpoints may be added to the extent that other costs vary.

The following formula shall apply to mitigated Energy Offer Curves for ESRs:

\[
\text{Charging Mitigated Energy Offer ($/MWh) = } \frac{\text{Performance Factor} \times \text{Average LMP Expected for the Next Hour ($/mmBtu)} \times \text{Round-Trip Efficiency} - \text{EOC VOM ($/MWh)}}{\text{Discharging Mitigated Energy Offer ($/MWh)}}
\]
E. Intra-day changes to the mitigated Energy Offer Curve are allowed under the following conditions:

1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period by the Day-Ahead Market or a RUC process, the Market Participant may submit an updated mitigated energy offer curve that reflects the procurement of higher cost fuel;

2) A Resource must switch fuels due to unforeseen operating conditions;

3) A Market Participant employing the Quick-Start Resource logic as described in the Market Protocols may update its mitigated Energy Offer Curve after the Day-Ahead RUC clears on the day before the Operating Day, as described in Appendix G of the Market Protocols;

4) The Resource is an ESR

Intra-day changes to the mitigated energy offer curve must follow the mitigated offer development guidelines in Appendix G of the Market Protocols. Any such changes will be validated by the Market Monitor.

F. In all cases under this Section 3.2, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.3 Mitigation Measures for Start-Up Offers and No-Load Offers

A mitigated Start-Up Offer and a mitigated No-Load Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. The mitigated Start-Up and No-Load Offers
may be updated up to the close of the Day-Ahead Market for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the Start-Up and No-Load Offers may be updated until the Day-Ahead RUC begins. The mitigated Start-Up and No-Load Offers submitted at the time the Day-Ahead RUC begins will apply to the Day-Ahead RUC on the day before the Operating Day and the Intra-Day RUC on the Operating Day unless an exception is allowed in section 3.3.F of this Attachment AF.

A. The Start-Up and No-Load Offer conduct thresholds are as follows:

1. For Resources committed to address a Local Reliability Issue, the conduct threshold is a 10% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable;
2. For all other Resources the conduct threshold is a 25% increase above the mitigated Start-Up or mitigated No-Load Offer, as applicable.

B. The Transmission Provider shall apply mitigation measures by replacing the Start-Up or No-Load Offer with the applicable mitigated Start-Up or No-Load Offer if:

1. The Resource’s Start-Up or No-Load Offer exceeds the mitigated Start-Up or mitigated No-Load Offer, as applicable, by the applicable conduct threshold; and
2. The Resource has local market power as determined in Section 3.1; and
3. The Resource either:
   a. Fails the Market Impact Test as described in Section 3.7, or
   b. Is manually committed by the Transmission Provider or by a local transmission operator.

C. The mitigated Start-Up Offer shall represent the cost per start as determined from start fuel usage and the costs related to that fuel usage, Performance Factor cost of electricity for station use to start (“Station Service”), maintenance costs attributed to starts, and additional labor costs, if required...
above normal station staffing levels. The following formula shall apply to all mitigated Start-Up Offers:

\[
\text{Mitigated Start-Up Offer (}\$/\text{Start}) = (\text{Start Fuel (mmBtu/Start)}) \times \text{Total Fuel Related Costs ($/mmBtu)} \times \text{Performance Factor} + (\text{Station Service (MWh/Start)}) \times \text{Station Service Rate ($/MWh)} + \text{Start VOM ($/Start)} + \text{Start Additional Labor Cost ($/Start)}
\]

The mitigated Start-Up Offer for Demand Response resources shall be the cost to shut down or curtail load for a given period, which varies with the number of deployments rather than the amount of response, and/or the start cost of Behind-The-Meter Generation utilizing the mitigated Start-Up Offer calculation applicable to other generation Resources as defined above.

The mitigated Start-Up Offer for Variable Energy Resources shall be zero.

D. The mitigated No-Load Offer shall be the hourly fixed cost required to create a monotonically increasing mitigated Energy Offer Curve. It shall be calculated according to either of two methods:

1. No-Load Fuel Approach

\[
\text{Mitigated No-Load Offer (}\$/\text{hour}) = \text{No Load Fuel (mmBtu/hour)} \times \text{Performance Factor} \times (\text{No-Load VOM ($/mmBtu)} + \text{Total Fuel Related Cost ($/mmBtu)}
\]

2. No-Load Cost Approach

\[
\text{Mitigated No-Load Offer (}\$/\text{hour) = (Heat Input at Minimum Economic Capacity Operating Limit (mmBtu)} \times \text{Performance Factor} \times (\text{Total Fuel Related Cost ($/mmBtu)} + \text{No Load VOM ($/mmBtu)}) \times (\text{Incremental Cost up to Minimum Economic Capacity Operating Limit ($/MWh)} \times \text{Minimum Economic Capacity Operating Limit (MW)})
\]
The mitigated No-Load Offer for Demand Response Resources utilizing Behind-The-Meter Generation shall adhere to the same definition above as a generating Resource. For Demand Response Resources utilizing load reduction, the mitigated No-Load Offer shall not exceed the quantifiable ongoing hourly costs associated with load reduction.

The mitigated No-Load Offer for Variable Energy Resources shall be zero.

E. The Market Participant shall submit all inputs used in calculating mitigated Start-Up and mitigated No-Load Offers to permit the Market Monitor to verify submitted offers. Required information includes: heat rate curves, descriptions of how spot fuel prices and/or contract prices are used to calculate fuel costs, variable fuel transportation and handling costs, emissions costs, and VOM. All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. Information to be provided by the Market Participant shall include the following:

1. For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

2. For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

3. For VOM costs, Market Participants shall submit VOM costs reflecting short-run marginal costs, exclusive of fixed costs.
Further details associated with the development, validation and updating of these costs are included in Appendix G of the Market Protocols.

F. Intra-day changes to the mitigated Start-Up and mitigated No-Load Offers are allowed under the following conditions:

1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period, the Market Participant may submit updated mitigated Start-Up and mitigated No-Load Offers that reflect the procurement of higher cost fuel;

2) A Resource must switch fuels due to unforeseen operating conditions; or

3) A Market Participant employing the Quick-Start Resource logic as described in the Market Protocols may update its mitigated Start-Up and mitigated No-Load offers as described in Appendix G of the Market Protocols; or

4) The Resource is an ESR.

Intra-day changes to the mitigated Start-Up and mitigated No-Load offers must follow the mitigated offer development guidelines Appendix G of in the Market Protocols. Any such changes will be validated by the Market Monitor.

G. In all cases under this Section 3.3, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.3.1 Mitigation Measures for Transition State Offers

The mitigation measures in this section apply only to MCRs. A mitigated Transition State Offer shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines specified in the Market Protocols for each potential transition state changes. The mitigated Transition State offer may be updated up to the close of the Day-Ahead
Market before the Operating Day as defined in Section 5.1 of Attachment AE of this Tariff for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Transition State Offer may be updated until the Day-Ahead RUC process begins. The mitigated Transition State Offer submitted at the time the Day-Ahead RUC process begins will apply to the Day-Ahead RUC process on the day before the Operating Day and Intra-Day RUC processes on the Operating Day.

A. The Transition State Offer conduct thresholds are as follows:
   (1) For Resources committed to address a Local Reliability Issue, the conduct threshold is a 10% increase above the mitigated Transition State Offer;
   (2) For all other Resources the conduct threshold is a 25% increase above the mitigated Transition State Offer.

B. The Transmission Provider shall apply mitigation measures by replacing the Transition State Offer with the mitigated Transition State Offer if:
   (1) The Resource’s Transition State Offer exceeds the mitigated Transition State Offer by the applicable conduct threshold; and
   (2) The Resource has local market power as determined in Section 3.1; and
   (3) The Resource either:
      (a) Fails the Market Impact Test as described in Section 3.7, or
      (b) Is manually committed by the Transmission Provider or by a local transmission operator.

C. The mitigated Transition State Offer for an MCR shall represent the costs of moving from the current configuration to another configuration as determined from the fuel costs incurred during the transition, the costs related to that fuel usage, Performance Factor,
additional maintenance costs incurred during the transition, and additional labor costs incurred during the transition, if required above normal station staffing levels. The following formula shall apply to all mitigated Transition State Offers:

Mitigated Transition State Offer ($/Transition) =
(Transition Fuel Consumed (mmBtu/Transition) * Total Fuel Related Costs ($/mmBtu) * Performance Factor) + Transition VOM Cost ($/Transition) + Incremental Labor Cost ($/Transition)

The Market Participant shall submit documentation of the method and any cost data for calculating the mitigated Transition State Offer that is necessary to allow the Market Monitor to validate submitted offers. Further details associated with the development of these costs are included in the Market Protocols.

D. Intra-day changes to the mitigated Transition State Offers are allowed under the following conditions:

(1) In the event that the Transmission Provider requests that a Resource remain online past their commitment period, the Market Participant may submit an updated mitigated Transition State Offer that reflects the procurement of higher cost fuel; or

(2) A Resource must switch fuels due to unforeseen operating conditions.

Intra-day changes to the mitigated Transition State Offers must follow the mitigated offer development guidelines in Appendix G of the Market Protocols. Any such changes will be validated by the Market Monitor.

E. In all cases under this Section 3.3.1, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the
confidentiality provisions set forth in Section 11 of Attachment AE of the Tariff.

3.4 Mitigation Measures for Operating Reserve Offers

A mitigated offer for each Operating Reserve product shall be submitted daily by the Market Participant in accordance with the mitigated offer development guidelines in the Market Protocols. For MCRs for which a single configuration allows physical units to be swapped (e.g., Combustion Turbine 2 for Combustion Turbine 1), the costs used in the mitigated offer development for that configuration shall be those of the least cost physical unit that is available and can be swapped in such configuration. The mitigated Operating Reserve Offers may be updated up to the close of the Day-Ahead Market for use in the Day-Ahead Market. In the case a Resource is not committed by the Day-Ahead Market, the mitigated Operating Reserve Offers may be updated until the Day-Ahead RUC begins. For Resources committed by the Day-Ahead Market, the mitigated Operating Reserve Offers submitted as of the close of the Day-Ahead Market will apply to the Day-Ahead Market on the day before the Operating Day and the RTBM on the Operating Day unless an exception is allowed in Section 3.4.F of this Attachment AF; for all other Resources, the mitigated Operating Reserve Offers submitted at the time the Day-Ahead RUC begins will apply to the RTBM on the Operating Day.

A. The offer conduct thresholds for each of the Operating Reserve products are as follows:

1. For Resources committed to address a Local Reliability Issue, the conduct threshold is a 10% increase above the mitigated offer for the applicable Operating Reserve Offer;

2. For all other Resources, the conduct threshold is a 25% increase above the mitigated offer for the applicable Operating Reserve Offer.

B. Any Operating Reserve Offer exceeding the applicable threshold, except offers below $10/MWh, will be deemed excessive. The Transmission
Provider shall apply mitigation measures by replacing the Operating Reserve Offer with the applicable mitigated Operating Reserve Offer if:

1. The Resource’s Operating Reserve Offer exceeds the applicable mitigated offer by the conduct threshold; and
2. The Resource has local market power as determined in Section 3.1; and
3. The Resource either:
   a. Fails the Market Impact Test as described in Section 3.7, or
   b. Is manually committed by the Transmission Provider or by a local transmission operator.

C. The mitigated Spinning Reserve Offer shall be equal to zero for Resources other than combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser. No known incremental costs are incurred for providing Spinning Reserves from other resource types. Total mitigated Spinning Reserve Offer for combustion turbines, reciprocating engines and hydro Resources operating as a synchronous condenser shall not exceed any additional fuel related costs, maintenance costs and power consumption costs necessary for the Resource to be prepared for deployment of Spinning Reserve:

\[
\text{Mitigated Spinning Reserve Offer ($/MW)} \leq \frac{\text{Additional Fuel Cost($/Hr) + Additional Maintenance Cost ($/Hr) + Condensing Power Cost ($/Hr) }}{\text{Spinning Reserve MW}}
\]

The mitigated Supplemental Reserve Offer shall not exceed labor costs necessary for the Resource to be prepared for deployment of Supplemental Reserve:

\[
\text{Mitigated Supplemental Reserve Offer ($/MW)} \leq \frac{\text{Additional Labor Cost($) }}{\text{Average Supplemental Reserve MW}}
\]

D. The mitigated Regulation-Up Service Offer shall not exceed the sum of the cost increase due to:

1. the heat rate increase during non-steady state operation,
(2) increase in VOM due to non-steady state operation,

(3) uncompensated costs, as described in the Market Protocols:

Where:

Mitigated Regulation-Up Service Offer = Mitigated Regulation-Up Offer ($/MW) + Mitigated Regulation-Up Mileage Offer ($/MW),

Mitigated Regulation-Up Offer ($/MW) ≤ Uncompensated Cost ($/MW), and

Mitigated Regulation-Up Mileage Offer ($/MW) ≤ (Cost Increase due to Heat Rate Increase during non-steady state operation + Cost Increase in VOM) * Regulation-Up Mileage Factor

E. The mitigated Regulation-Down Service Offer shall not exceed the sum of the cost increase due to:

(1) the heat rate increase during non-steady state operation,

(2) increase in VOM due to non-steady state operation,

(3) uncompensated costs, as described in the Market Protocols:

Where:

Mitigated Regulation-Down Service Offer = Mitigated Regulation-Down Offer ($/MW) + Mitigated Regulation-Down Mileage Offer ($/MW),

Mitigated Regulation-Down Offer ($/MW) ≤ Uncompensated Cost ($/MW), and

Mitigated Regulation-Down Mileage Offer ($/MW) ≤ (Cost Increase due to a decreased energy conversion efficiency (e.g., Heat Rate Increase) during non-steady state operation + Cost Increase in VOM) * Regulation-Down Mileage Factor

Further details associated with the development of the exact costs in the formulas above are included in the Market Protocols.

F. Intra-day changes to the mitigated Operating Reserve Offers are allowed under the following conditions:
1) In the event that the Transmission Provider requests that a Resource that is supplying Operating Reserves remain online past their commitment period by the Day-Ahead Market or a RUC process, the Market Participant may submit an updated mitigated Operating Reserve offer curve that reflects the procurement of higher cost fuel;

2) A Resource must switch fuels due to unforeseen operating conditions; or

3) Intra-day changes to the mitigated Regulation-Up and mitigated Regulation-Down Offers are allowed after the Day-Ahead RUC clears on the day before the Operating Day under the following condition:
   a. The Resource incurs the uncompensated cost in Section 3.4(D)(3) of this Attachment AF, for which the mitigated offer calculation is described in Appendix G of the Market Protocols.

Intra-day changes to the mitigated Operating Reserve Offer curve must follow the mitigated offer development guidelines in Appendix G and Section 8.2.2 of the Market Protocols. Any such changes will be validated by the Market Monitor.

G. The Market Participant may include in the calculation of its mitigated Operating Reserve Offer an amount reflecting the Resource-specific opportunity costs if the Market Participant is able to demonstrate to the satisfaction of the SPP Market Monitoring Unit that such costs are legitimate and verifiable and not otherwise included in market outcomes. To the extent such costs include run-time restrictions, such run-time restrictions shall be updated as specified in the Market Protocols, with more frequent updating to occur the fewer hours that remain available, consistent with the Market Protocols. The formulas and instructions in the price forecast model for any such opportunity costs shall be determined by the SPP Market Monitoring Unit and published in the Market Protocols as part of the Mitigated Offer Development Guidelines, updated, as needed, by the SPP Market Monitoring Unit. Opportunity costs for mitigated Operating
Reserve Offers shall not include Energy and Operating Reserve Markets revenues associated with forgone Energy or other types of Operating Reserve production to the extent that such costs are included in market outcomes.

H.  All cost data and cost calculation descriptions are subject to the review and approval of the SPP Market Monitoring Unit to ensure reasonableness and consistency across Market Participants. The information will be sufficient for replication of the mitigated Operating Reserve Offers and shall include, among other data, the following information:

1. For fuel costs, Market Participants shall provide the Market Monitoring Unit with an explanation of the Market Participants’ fuel cost policy, indicating whether fuel purchases are subject to a fixed contract price and/or spot pricing and specifying the contract price and/or referenced spot market prices. Any included fuel transportation and handling costs must be short-run marginal costs only, exclusive of fixed costs.

2. For emissions costs, Market Participants shall report the emissions rate of each of their units and indicate the applicable emissions allowance cost.

3. For VOM costs, Market Participants shall submit VOM costs, calculated in adherence with the Appendix G of the Market Protocols, reflecting short-run marginal costs, exclusive of fixed costs.

I. In all cases under this Section 3.4, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

3.5 Validation of Mitigated Resource Offer Parameters

The Market Monitor shall review the costs included in each mitigated Resource Offer on an ex-post basis relative to the relevant Operating Day in order to ensure that the Market Participant has correctly applied the formulas and definitions in Sections 3.2, 3.3,
3.3.1, and 3.4 of this Attachment AF and in the Market Protocols and that the level of the mitigated offer is otherwise acceptable. If the mitigated offer determined by the Market Monitor and the Market Participant differ, Market Participant shall use the mitigated offer calculated by the Market Monitor going forward. If a Market Participant submits a dispute over its mitigated offer, the previously approved mitigated offer shall be used from the time the dispute is submitted until the dispute is resolved. The procedures for submitting and processing disputes related to mitigated offers shall be those specified in the Market Protocols. The Transmission Provider shall remedy mitigated offer disputes resolved in favor of the Market Participant by providing make whole payments, as necessary, to the Market Participant whose mitigated offer was improperly determined by the Market Monitor.

Each Market Participant is obligated to provide to the Market Monitor any cost data necessary to allow the Market Monitor to validate its mitigated Resource Offer.

The Market Monitor shall keep such data confidential, and all cost data submitted under this Section 3.5, including any opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff. The Market Monitor shall develop and maintain on the Transmission Provider’s website the mechanism and procedures to allow Market Participants to submit such cost data.

3.6 Additional Mitigation Measures for Resource Offer Parameters

The mitigation measures in this section apply to all Resource Offer parameters expressed in units other than dollars and will only apply in the presence of local market power as described in Section 3.1 of this Attachment AF. A reference level for each applicable Resource Offer parameter that reflects the physical capability of the Resource shall be determined prior to the start of the Energy and Operating Reserve Markets by one or both of the following methods: (i) the reference levels will be determined through consultation between the Market Participant and the Market Monitor; and/or (ii) the reference levels will be based on averages of Resource Offer parameters from similar Resources. This methodology for setting reference levels for Offer parameters shall apply
to all Resources at the start of the Energy and Operating Reserve Markets and to all Resources that register subsequent to the start of the Energy and Operating Reserve Markets. The Transmission Provider’s output forecast for a wind-powered Variable Energy Resource shall be used as the reference maximum output limit for the wind-powered Variable Energy Resource.

The following thresholds shall be used by the Transmission Provider to identify Resource Offers that may warrant mitigation and shall be determined with respect to the corresponding reference level:

Time-based Resource Offer parameters: An increase of three (3) hours, or an increase of six (6) hours in total for multiple time-based Resource Offer parameters.

Resource Offer parameters expressed in units other than time or dollars: One hundred percent (100%) increase for Resource Offer parameters that are minimum values, or a fifty percent (50%) decrease for Resource Offer parameters that are maximum values.

Minimum Economic Capacity Operating Limit, Minimum Discharge Limit, or Maximum Charge Limit, as applicable, threshold for Resources committed to address a Local Reliability Issue: twenty-five percent (25%) increase.

Maximum Charge Limit, as applicable, threshold for Resources committed to address a Local Reliability Issue; twenty-five percent (25%) decrease.

In the case that a Resource Offer fails the thresholds described above, the Market Monitor shall determine the impact on prices or make whole payments. If an impact exceeds the LMP, MCP or make whole payment thresholds in Section 3.7, the Market Monitor will initiate a discussion with the Market Participant concerning an explanation of the parameter changes. The Market Monitor will inform the Transmission Provider of any potential issue. If the Transmission Provider, in consultation with the Market Monitor, concludes that the Market Participant has demonstrated the validity of the submitted Resource Offer parameter, no further action will be taken. If not, the Transmission Provider shall replace the Resource Offer parameter with the corresponding reference level. Mitigation measures will remain in place until such time that the Market Participant
demonstrates the validity of the Resource Offer parameter or the Market Participant notifies the Market Monitor that the Resource Offer parameter has been changed to a value that is within the tolerance range as described above, and the Market Monitor has verified that this change has occurred. In the event that the Market Participant submits a dispute, the mitigation measure will remain in place until the resolution of the dispute.

In all cases under this Section 3.6, cost data submitted for the development of mitigated offers, including opportunity cost data, shall be subject to the confidentiality provisions set forth in Section 11 of Attachment AE of this Tariff.

ATTACHMENT AG Market Monitoring Plan

4.6.1 Uneconomic Production

The Market Monitor will monitor for cases where uneconomic production by a Resource causes congestion on transmission facilities or price separation between Reserve Zones that is not justified by reliability concerns. For an MSR, both charging and discharging are considered production. The provisions of this Section 4.6.1 shall not apply to Demand Response Resources.

(a) Potential uneconomic production will be indicated, and subject to further analysis as described in (b) of this Section 4.6.1, when the Resource has a positive Resource-to-Load Distribution Factor and any of the following conditions are met:

1. a Resource is identified with an incremental energy offer price less than 50 percent of the applicable reference level; or

2. a Resource is determined to be generating outside of its Operating Tolerance; or
(3) a Resource is subject to a time-based or other resource offer parameter (non-time and non-dollar based) that appears to facilitate production that is otherwise uneconomic.

(b) For any Resource meeting the conditions described in (a) of this Section 4.6.1, the Market Monitor shall determine whether: (i) the MW impact from uneconomic production associated with such Resource is exacerbating the transmission congestion or binding a Reserve Zone; and (ii) the uneconomic production is not obviously justified by reliability or other operational concerns.

The Market Monitor will conduct evaluations as specified above and other related assessments to determine if there is sufficient credible information to justify referral to the Commission.

4.6.4 Physical Withholding

(1) The Market Monitor will monitor for physical withholding of capacity from the Energy and Operating Reserve Markets, and unavailability of facilities. Physical withholding and unavailability of facilities may include:

(a) Declaring that a Resource has been derated, forced out of service or otherwise been made unavailable for technical reasons that are untrue or that cannot be verified;

(b) Refusing to provide offers or schedules for a Resource when it would otherwise have been in the economic interest to do so without market power;

(c) Operating a Resource in real-time to produce an output level that is less than the Dispatch Instruction minus the Resource’s Operating Tolerance defined in Section 6.4.1 of Attachment AE to this Tariff and the Resource is not exempt

Commented [PK24]: MMU added language in this section to reflect Order 841 requirements.
from URD under Section 6.4.11 of Attachment AE to this Tariff;

(d) Derating a transmission facility for technical reasons that are not true or verifiable;

(e) Operating a transmission facility in a manner that is not economic and that causes a binding transmission constraint or binding reserve zone or local reliability issue; and

(f) Declaring that the magnitude of the capability of a Resources is reduced for reasons that are not true or verifiable. This capability includes but is not limited to the following:
   (i) The capability to provide Energy;
   (ii) The capability to provide or Operating Reserves is reduced for reasons that are not true or verifiable;
   (iii) In the case of MSRs, the capability to charge and/or to discharge.

(2) Market Participants will not be deemed to be physically withholding if:
   (a) They are following the directions of the SPP Balancing Authority, Reliability Coordinator, or applicable reliability standards.

   (b) In addition, Market Participants will not be determined to have physically withheld if they are selling into another market at a higher price.

   (c) Their Variable Energy Resources are withheld will not be determined to be physically withheld in the Day-Ahead Market under the conditions in Sections 4.6.4(a), 4.6.4(b), or 4.6.4(f).

   (d) The Market Participant is reducing the magnitude of the MSR’s maximum capability, either charging or discharging.

Commented [PK25]: From Paragraph 93, the Order states: “…to require each RTO/ISO to revise its tariff to allow electric storage resources to de-rate their capacity to meet minimum run-time requirements.”
from its true and verifiable physical or environmental limitations in order to provide that capability for the duration of the minimum clearable commitment period.