**Southwest Power Pool**

**SCHEDULE 1A TASK FORCE MEETING**

**December 18, 2018**

**Teleconference**

**• M I N U T E S •**

**Administrative Items**

Chair John Olsen called the meeting to order at 1:00 PM. The following individuals participated in the meeting:

| | |
|---|---|
| John Olsen | Evergy |
| Jason Mazigian | Basin Electric |
| David Mindham | ITC Holdings |
| Tim Hall | Southern Power |
| Wes Berger | SPS/Xcel Energy |
| Greg Garst | OPPD |
| Alfred Busbee | GDS Associates/ETEC |
| Jim Jacoby | AEP – Public Service Co. of Oklahoma |
| Ray Bergmeier | Sunflower Electric |
| Robert Janssen | Dogwood Energy, LLC |
| Dennis Reed | Midwest Regulatory Consulting, LLC |
| Chris Lyons | Customized Energy Solutions |
| Ishwar Saini | Macquarie Energy, LLC |
| Seth Cochran | DC Energy |
| Andrea Harrison | Western Farmers Elec Coop. |
| Brian Rounds | AESL Consulting |
| J.P. Maddock | Basin Electric |
| Jessica Meyer | Lincoln Electric System |
| Lisa Szot | Enel Green Power N.A., Inc. |
| Sandy Wirkus | WAPA |
| Carrie Dixon | Xcel |
| Chris Green | Liberty (Empire) |
| Carl Monroe | SPP |
| Tom Dunn | SPP |
| Mike Riley | SPP |
| David Daniels | SPP |
| Scott Smith | SPP |
| Will Vestal | SPP |
| John Luallen | SPP |
| Tony Alexander | SPP |
| Patti Kelly | SPP |
| Dianne Branch | SPP |

Minutes from the November 27, 2018 meeting were reviewed. Jason Mazigian motioned to approve the minutes. The motion was seconded by Jim Jacoby. The minutes were unanimously approved by voice vote.

The following proxies were in effect for the meeting –Rob Janssen for Heather Starnes and John Olsen for Joel Dagerman (see attachments).

**Update on Action Items from 11/27/18 Meeting**

1) **Update Proposed Rate Schedules for the following items**
   a. RS 1 – Add Scheduling & Dispatch costs from RS 4
      RS 4 – Remove Scheduling & Dispatch costs
   b. Consider additional costs from Market Facilitation (RS 4) that would be reasonable to include in the Market Clearing cost (RS 3).
   c. Combine RS 3 and RS 4 (as amended for item a. above), utilizing a denominator that would incorporate deviations from the DA market.

   UPDATE: These items were covered under Agenda Items 3 and 4 of the current meeting.

2) **Obtain Opinion from the Market Monitoring Unit**
   Under the assumption that we establish rates based on only RT activity, will the MMU be receptive to market participants adding those rates to both their DA and RT mitigated offers.

   UPDATE: Will Vestal from the MMU provided a response to this action item. His comments addressing this action item during the meeting and the follow-up question by Rob Janssen has been captured in a separate document that is included as an attachment to these meeting minutes.

3) **Notation in Minutes for TCR Rate Structure**
   Ensure that minutes reflect the TCR rate structure approved by the task force in Motion #1 is based strictly on the system and processes in effect today. Any future changes (and its impact to our rate structure) would need to be contemplated at that future time.

   UPDATE: The approved 11/27 meeting minutes included the appropriate notation regarding the conditions under which the TCR Rate structure was approved.

**Day Ahead (DA) and Real Time (RT) Metrics**

David Daniels walked through various scenarios utilizing both DA and RT metrics as potential billing determinants for our market based rate schedules. Scenarios presented included 1) taking the maximum value of DA and RT, 2) charging for both DA and RT, and 3) utilizing DA + Incremental (absolute). It was pointed out that the last option is similar to MISO's current methodology. David then presented metrics for DA and RT, illustrating the impact to generation, load, imports, and exports from utilizing the three scenarios previously discussed. David wrapped up his presentation by summarizing some of the potential impacts of utilizing DA information as a billing determinant. He highlighted the potential for discriminatory treatment if different rules were applied to generation and load; the difficulty in forecasting DA activity resulting in potentially large true-ups and increased volatility in rates; and the cost impact to both SPP and market participants. As it relates to the cost impacts, David indicated that while the cost associated with system changes would be small, there was greater concern over the potential for an increase in disputes given the increased complexity from utilizing DA information. More disputes could lead to more FTEs being needed to handle the resolution of those disputes. There was a brief discussion and some general questions that were addressed by staff.

**Review of Market Based Rate Schedules**

Dianne Branch presented an overview of the rate schedules that had been previously approved (Rate Schedule 1 and 2) and the market related rate schedules that were still under debate (Rate Schedules 3 and 4). A summary of those rate schedules is as follows:

- Rate Schedule 1 (RS 1) – Planning and Scheduling & Dispatch costs based on 12 CP billing determinants
- Rate Schedule 2 (RS 2)– TCR administration costs based on TCRs awarded and converted
- Rate Schedule 3 (as originally presented) – Market clearing costs based on RT billing determinants (including virtuals)
- Rate Schedule 4 (as originally presented) – Market administration costs (excluding TCR and market clearing costs) based on RT billing determinants (excluding virtuals)
- Rate Schedules 3 and 4 (combined view) – Market administration costs (excluding TCR costs) based on RT billing determinants (including virtuals)

Dianne Branch also presented revisions to RS 3 and RS 4 that reflected a shift in costs for IT staffing costs identified as being associated with the market clearing process. Shifting these costs from RS 4 to RS 3 had a cost impact of approximately $0.01/MWh (increase to RS 3, decrease to RS 4).

Following a fair amount of discussion about the analysis presented by David Daniels regarding the utilization of DA metrics as a billing determinant and the presentation of RS 3 and RS 4 that reflected the adjustments for the shift in IT costs, Rob Janssen made a motion to approve RS 3 and RS 4 as summarized below:

- Rate Schedule 3 (as adjusted) – Market clearing costs based on RT billing determinants (including virtuals)
- Rate Schedule 4 (as adjusted) – Market administration costs (excluding TCR and market clearing costs) based on RT billing determinants (excluding virtuals)

The motion was seconded by Jim Jacoby. A roll call was utilized to collect the votes on this motion. The results were as follows – 10 voted for the motion, 1 voted against the motion, and 1 abstained from the vote. The following rational was provided for the No vote –

> Xcel (SPS) – While in agreement on the components of the numerator and denominator, representative believes that it would be more appropriate to use the maximum of the Day-ahead and Real-time for the denominator as opposed to simply using Real-time.

**Discussion on True-Up Cadence for Rate Schedules**

Dianne Branch provided a recap of the frequencies utilized by other RTO/ISOs to update their rates. The RTO/ISOs captured in this analysis included MISO, PJM, CAISO, ISO-NE, and NYISO. With the exception of MISO, all entities utilized an annual rate setting/true-up process. Conversely, MISO performs true-ups/rate adjustments on a monthly basis. While there was a brief, general discussion on preferences and potential advantages/disadvantages of using an annual vs. more frequent alternative, it was agreed that a final decision on frequency of true-ups could not be made until SPP staff performed additional analysis on cash flows utilizing the agreed upon rate schedules.

**Action Items**

1 - With respect to the MMU's response to action item # 2 from the November 27th meeting that was communicated during this meeting and the follow up question by Rob Janssen and the related MMU response - a document summarizing these items should be included as an attachment to the December 18th meeting minutes.

2 – SPP staff to perform a multi-year cash flow analysis utilizing the metrics and rates agreed upon by the 1ATF. A sensitivity analysis should also be incorporated to contemplate impacts that fluctuations in metrics could have on cash flows. The analysis should also identify thresholds that would potentially serve as trigger points for off cycle true-ups.

**Future Meetings**

Thursday, January 17th 9-10AM – Teleconference/Web-Ex
Tuesday, February 5th 8AM-2PM – Face to Face – DFW Hyatt

There being no further business, John Olsen adjourned the meeting at 3:10 PM.

Respectfully Submitted,

Dianne Branch
Secretary

## Dianne Branch

**From:** Starnes, Heather
**Sent:** Wednesday, December 12, 2018 10:44 AM
**To:** Olsen, John; Dianne Branch
**Cc:** Janssen, Rob
**Subject:** **External Email** 1-ATF meeting

Due to a conflict, I will be late getting on our call next week. I would like Rob Janssen to have my proxy until I can participate.

Thanks!

Heather Starnes, Esq.
Healy Law Offices, LLC
(501) 516-0041

NOTE: The Missouri Bar Disciplinary Counsel and the Arkansas Bar require all Missouri and Arkansas attorneys to notify all recipients of email that (1) email communication is not a secure form of communication; (2) any email that is sent to you or by you may be copied and held by various computers it passes through as it goes from sender to recipient; (3) persons not participating in our communication may intercept our communications by improperly accessing your computer or my computer or even some computer unconnected to either of us which the email passes through. I am communicating to you via email because you have consented to receive communications via this medium. If you change your mind and want future communications to be sent in a different fashion, please advise me at once.
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## Dianne Branch

**From:** Dagerman, Joel
**Sent:** Tuesday, December 18, 2018 11:39 AM
**To:** Olsen, John
**Cc:** Dianne Branch
**Subject:** **External Email** RE: SPP 1A Meeting 12/18

Unfortunately, I do not have consistent cell or internet access for Tuesday's meeting. I will call in when available otherwise I will give my proxy to the Chair.


Joel L. Dagerman, P.E.
**Senior System Planning & Transmission Business Manager**
**Nebraska Public Power District**

**Bell - (402) 644-3300 / Cell (402) 649-0093**



*If you've received this message in error, I apologize for the inconvenience. Please don't distribute it. Instead, please just delete it and respond to let me know of my error. Then, have a wonderful day.*

**Southwest Power Pool**

**SCHEDULE 1A TASK FORCE MEETING**

**November 27, 2018**

**AEP Offices – Dallas, TX**

**• M I N U T E S •**

**Administrative Items**
Chair John Olsen called the meeting to order at 8:05 AM. The following individuals participated in the meeting:

| | |
|---|---|
| Jim Jacoby | AEP-Public Service Company of Oklahoma |
| Jason Mazigian | Basin Electric |
| John Varnell | Tenaska |
| Tom Dunn | SPP |
| Mike Riley | SPP |
| Dianne Branch | SPP |

Those participating by phone were as follows:

| | |
|---|---|
| John Olsen | Evergy |
| Tim Hall | Southern Power |
| Robert Tallman | OG&E |
| Joel Dagerman | NPPD |
| Heather Starnes | Healy Law Offices/MJMEUC |
| Greg Garst | OPPD |
| Wes Berger | Xcel (SPS) |
| Alfred Busbee | GDS Associates/ETEC |
| Rob Janssen | Dogwood Energy |
| Jeff Bieker | Sunflower Electric |
| David Erkin | AEP |
| Seth Cochran | DC Energy |
| Ronald Thompson, Jr. | NPPD |
| Sandy Wirkus | WAPA |
| Jessica Meyer | Lincoln Electric System |
| Carl Monroe | SPP |
| Scott Smith | SPP |
| Micha Bailey | SPP |
| David Daniels | SPP |
| Patti Kelly | SPP |
| Tony Alexander | SPP |

Minutes from the November 9, 2018 teleconference meeting were reviewed. Amendments to the minutes were as follows – Ray Bergmeier had given his proxy to Dennis Reed and Alfred Busbee and Joel Dagerman should have been listed as participating in the meeting. Bob Tallman motioned to approve the minutes as amended. The motion was seconded by Heather Starnes. The minutes as amended were unanimously approved by voice vote.

The following proxies were in effect for the full meeting – Jeff Bieker for Ray Bergmeier and Tim Hall for David Mindham (see attachments). The following proxies went into effect at approximately 1:30 PM – John Olsen for Joel Dagerman and Rob Janssen for Tim Hall (see attachments).

## Review of Past Action Items

Strawman Rate Schedule Proposal

- Proposed rate schedules were discussed in Agenda Item #4

RTO/ISO TCR Rate Schedule Comparison

- Comparative analysis was reviewed in Agenda Item #3

## RTO/ISO TCR Rate Comparison

Dianne Branch provided an overview of how other RTO/ISOs charged for their TCR related functions. The various rate methodologies are summarized as follows:

- MISO and NYISO– MWh clearing charge only
- PJM and CAISO – per bid transactional charge and MWh clearing charge
- ISO NE – per bid transaction charge only (submitted and cleared)

All RTO/ISOs update their rates annually with the exception of MISO who updates their rate on a monthly basis. There was a brief discussion and some general questions that were addressed by staff.

## Discussion on Proposed Rate Schedules

John Olsen provided a brief overview of the four rate schedules that were prepared by staff and included in the meeting materials. A brief synopsis for each rate schedule is provided below.

- Rate Schedule #1 (RS 1)
  Recovers Reliability Planning costs based on demand (12CP)
- Rate Schedule #2 (RS 2)
  Recovers TCR administration costs based on MWhs of TCRs awarded and converted
- Rate Schedule #3 (RS 3)
  Recovers costs associated with Market Clearing based on MWhs cleared on Real Time Generation, Load, Imports/Exports, and Virtuals
- Rate Schedule #4 (RS 4)
  Recovers costs associated with Market Facilitation (less TCR and Market Clearing costs recovered in RS 2 and RS 3) and Scheduling & Dispatch allocated based on MWhs of Real Time Generation, Load, and Imports/Exports

The discussion initially centered on the TCR administrative charge (RS 2 in the materials) which resulted in a motion and vote that is summarized as follows -

Motion # 1 (Made by Rob Janssen, seconded by Tim Hall)
To approve RS 2 for the recovery of costs to administer the TCR market. This would include all TCRs settled regardless of how obtained. Additionally, this motion is based on the TCR processes and systems as they exist today. Any impact that future changes to the TCR process might have to this rate schedule would be addressed concurrently as those changes are formally considered.

The motion passed by voice vote with AEP(PSCO) and NPPD voting no and OG&E abstaining from the vote. The following rationale was provided from those representatives voting no:

- AEP (PSCO) - Did not agree that the denominator should include all "TCRs awarded or converted" and specifically noted that TCRs converted from ARRs should be excluded given that ARRs have already been paid through transmission service charges, and therefore should be excluded from this separate TCR administrative charge.
- NPPD – Preferred a denominator that included only those TCR volumes that exceed the load values for a specific settlement location, which represents those TCRs that are in excess of hedges for native load. Using this approach would provide for a reasonable compromise to ensure fair but not excessive costs and would preclude any unnecessary double "administrative" billing to hedge native load.

There was a lengthy discussion on RS 3 (Market Clearing) and RS 4 (Market Facilitation /Scheduling & Dispatch). Certain members voiced their concern that two separate schedules based on market metrics made things unnecessarily complicated. Staff reminded the task force that the primary reason for preparing a separate schedule for market clearing costs (RS 3) was to address previous concerns that virtuals should pay for something but that it should not be cost prohibitive. Instead of assigning all market costs to virtual transactions, costs associated with clearing the market were identified and removed from the market facilitation cost pool of RS 4, and a separate rate schedule was created (RS 3). A straw poll was taken to gauge how the members felt about having a singular market based rate schedule vs. two separate schedules as presented in the materials (RS 3 and RS 4). The majority preferred the two schedule approach as presented in the materials. An action item was assigned to staff to consider whether there are additional costs included in the Market Facilitation cost base (RS 4) that would be reasonable to assign to the Market Clearing cost base (RS 3).

Upon further discussion of the merits of RS 3 and RS 4, the question of whether day-ahead (DA) results should be considered in the denominator as opposed to allocating costs based strictly on real time (RT) activity as is currently contemplated in both RS 3 and RS 4. A straw poll was taken to assess members' position on whether DA activity should be considered in our proposed rate schedules. Based on the straw poll, members were evenly split between only using RT data and the inclusion of DA activity. An additional straw poll was taken to discern preference between DA + Meter vs. RT + Deviation to DA under the scenario that we would consider DA results in our market based rate structures. The majority supported the RT + Deviation to DA option.

Settlements staff indicated that DA activity was available and could be analyzed for purposes of creating rate structures that would incorporate DA activity. The task force decided that until DA data was incorporated into these rate structure proposals, no decision could be made. An action item was assigned for staff to perform additional analysis with DA data incorporated into the market based rate structure.

With respect to RS 4's inclusion of scheduling & dispatch costs, several members voiced concern with allocating these costs based on energy metrics. After a fair amount of discussion, the following motion was made -

<u>Motion # 2 (Made by Rob Janssen, seconded by John Varnell)</u>
To move costs associated with Scheduling & Dispatch from RS 4 to RS 1, which includes costs associated with Reliability and Planning and is allocated based on demand metrics (12CP).

The motion passed by voice vote with OG&E and OPPD voting no and Basin Electric and NPPD abstaining from the vote. The following rationale was provided from those representatives voting no:

- OG&E – Is not convinced that the denominator for RS 1 is correct for these costs, further stating that dispatch is a service to generators and that supply should share in the costs for SPP providing that function.
- OPPD – Believes that the scheduling and dispatch costs should be based on energy usage (RS 4) rather than demand (RS 1).

**Discussion on True-Up Cadence for Rate Schedules**

There was a brief, general discussion on the issue of desired frequency of rate schedule true-ups. Impacts to cash flows and administrative burden of the true-up process will both need to be considered in determining the appropriate frequency of true-ups. Ultimate decision will be deferred until the proposed rate structure is more fully solidified.

**Action Items**

1) **Update Proposed Rate Schedules for the following items**
   a. RS 1 – Add Scheduling & Dispatch costs from RS 4
      RS 4 – Remove Scheduling & Dispatch costs
   b. Consider additional costs from Market Facilitation (RS 4) that would be reasonable to include in the Market Clearing cost (RS 3).
   c. Combine RS 3 and RS 4 (as amended for item a. above), utilizing a denominator that would incorporate deviations from the DA market.

2) **Obtain Opinion from the Market Monitoring Unit**
   Under the assumption that we establish rates based on only RT activity, will the MMU be receptive to market participants adding those rates to both their DA and RT mitigated offers.

3) **Notation in Minutes for TCR Rate Structure**
   Ensure that minutes reflect the TCR rate structure approved by the task force in Motion #1 is based strictly on the system and processes in effect today. Any future changes (and its impact to our rate structure) would need to be contemplated at that future time.

**Future Meetings**

Tuesday, December 18th 1-4PM - Teleconference

There being no further business, John Olsen adjourned the meeting at 2:45 PM.

Respectfully Submitted,

Dianne Branch
Secretary

# CORRESPONDENCE FROM MARKET MONITORING UNIT (MMU)

**Original Action Item from November 27th Meeting:**

Obtain Opinion from the Market Monitoring Unit
Under the assumption that we establish rates based on only RT activity, will the MMU be receptive to market participants adding those rates to both their DA and RT mitigated offers.

**MMU Response:**

The RTO's market based proposals vary in calculation method; however, all of the market-based methods relate in that they recover the projected budget through MWh. Therefore, the market-based forms of cost recovery allow the associated administrative costs to be classified as short-run marginal costs. As such, the MMU would be receptive to the inclusion of these short-run marginal costs in mitigated energy offer curves. In almost all cases, there is not a distinction between day-ahead and real-time mitigated offers and therefore we would expect these costs to be included in the mitigated offers used in both the day-ahead and real-time markets.

If the RTO moved toward a revenue requirement approach, where market participants were assessed based on their percentage of billing units over a given period, the market monitor would be less receptive to the inclusion of these costs in mitigated offers. Under such a scenario, a market participant would need to estimate their administrative cost per unit. Ensuring that all market participant estimates were just and reasonable could prove difficult and unduly burdensome.

**Rob Jannsen Follow-up Question from December 18th Meeting:**

Rate schedules 3 (Market Clearing) and 4 (Market Facilitation) have been approved for application to Real Time Generation, Load, and Imports/Exports for Schedule 4, with Virtual Energy also included for Schedule 3. The charges for these schedules are not explicitly or implicitly being charged to Day Ahead transactions, other than Virtuals. If Market Participants do not include the Schedule 3 and 4 charges in their Day Ahead transactions (other than Virtuals), there could be a built-in difference of roughly 15 cents per MWh in offers in the two energy markets as a result. Does such a potential difference in offers raise a concern for the Market Monitoring Unit in terms of convergence of the Day Ahead and Real Time markets, or any other relevant market issue such as competition between Virtuals and other Day Ahead offers?

**MMU Response:**

The market monitor does not inform market participants on what can or cannot be included in market offers. We would view the costs related to rate schedules 3 and 4 in the same way. Thus, participants will include or not include these costs in their market offers based on their own decisions.

With respect to mitigated offers, the market monitor retains its position that these costs are short-run marginal costs, and therefore, valid inclusions in mitigated offers. The market monitor will allow the inclusion of these costs in mitigated offers, but may not require their inclusion. Market participants reflect the construction of their mitigated offer in their fuel policy, which the market monitor validates. In almost all cases, there is not a distinction between day-ahead and real-time mitigated offers for most resources. In other words, the fuel cost policy developed for the real-time market would be identical to the day-ahead market for almost all resources. The primary exception is the proposed change related to the fuel policy for energy storage resources.

Regarding the question of divergence, because these costs are allowed in both the day-ahead and real-time markets -- it is the position of the market monitor that rate schedules 3 and 4 will likely not affect divergence between the day-ahead and real-time markets, and the Integrated Marketplace will remain workably competitive.

Additionally, in order for price divergence to stem solely from the inclusion of these administrative costs in either market or mitigated offers, the day-ahead and real-time markets would need to be in perfect alignment in every other aspect. While this is the ideal outcome for two-day markets such as the SPP Integrated Marketplace, perfect market alignment is extremely infrequent.

Given the current level of energy prices and the estimated cost associated with proposed rate schedules 3 and 4, the magnitude of a price divergence stemming from the treatment of these costs in offers would amount to less than one percent in both the day-ahead and real-time markets. There is significant variation in prices based on other factors (including wind and load forecast variations) between the day-ahead and real-time markets that are more likely to cause price divergence and mask any divergence associated with these costs.

# Schedule 3 and 4 Revisions

Addition to Agenda Item #4

1ATF Teleconference December 18, 2018

SouthwestPowerPool SPPorg southwest-power-pool

# Rate Schedule #3 w/ Additional IT Costs

| Rate Schedule #3 | | |
|---|---|---|
| **Market Clearing** | | |
| Market Monitoring | $3.0 | MM |
| Settlements | $2.8 | MM |
| Information Technology | $2.4 | MM |
| Credit | $0.7 | MM |
| Customer Relations (allocation) | $0.9 | MM |
| Clearing Overhead | $9.2 | MM |
| Market Clearing Costs | $19.0 | MM |
| | | |
| Real Time Generation | 260 | TWh |
| Real Time Load | 250 | TWh |
| Real Time Import/Export | 18 | TWh |
| Virtual Energy | 35 | TWh |
| Market Clearing Denominator | 563 | TWh |
| | | |
| **Market Clearing Rate** | $0.034 | / MWh |

Represents a cost shift of approximately 4.7MM or $0.01/MWh increase

SPP

# Rate Schedule #4 w/ select IT Costs Removed

| Rate Schedule #4 | | |
|---|---|---|
| **Market Faciliation** | | |
| Market Facilitation | $87.6 | MM |
| Less: TCR Admin Costs | ($4.4) | MM |
| Less: Market Clearing Costs | ($19.0) | MM |
| Market Facilitation Costs | $64.3 | MM |
| | | |
| Real Time Generation | 260 | TWh |
| Real Time Load | 250 | TWh |
| Real Time Import/Export | 18 | TWh |
| Market Denominator | 528 | TWh |
| | | |
| **Market Facilitation Rate** | $0.122 | / MWh |

Represents a cost shift of approximately 4.7MM or $0.01/MWh decrease

SPP