Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

February 21, 2019

DFW Hyatt Regency – Dallas, TX

• M I N U T E S •

Administrative Items
Chair John Olsen called the meeting to order at 8:00 AM. The following individuals participated in the meeting:

John Olsen	Evergy
Jim Jacoby	AEP-Public Service Company of Oklahoma
Jason Mazigian	Basin Electric
John Varnell	Tenaska
Robert Tallman	OG&E
David Mindham	ITC Holdings Corp.
Wes Berger	Xcel Energy/SPS
Ray Bergmeier	Sunflower Electric
Mike Riley	SPP
Dianne Branch	SPP

Those participating by phone were as follows:

Alfred Busbee	GDS Associates/ETEC
Greg Garst	OPPD
Joel Dagerman	NPPD
Heather Starnes	Healy Law Offices/MJMEUC
Rob Janssen	Dogwood Energy
Calvin Daniels	Western Farmers
Chris Lyons	Customized Energy Solutions
Damir Domazet	The Energy Authority
David Erkin	AEP
David Kays	OG&E
Greg McAuley	OG&E – Transmission
J.P. Maddock	Basin Electric
Lee Anderson	Lincoln Electric System
Jessica Meyer	Lincoln Electric System
Ron Thompson	NPPD
Sandy Wirkus	WAPA
David Daniels	SPP
Steve Davis	SPP
Richard Dillon	SPP
Nicole Wagner	SPP
Chris Cranford	SPP
Lee Elliot	SPP
Patti Kelly	SPP

Minutes from the February 5, 2019 meeting were reviewed. Jason Mazigian motioned to approve the minutes. The motion was seconded by John Varnell. The minutes were unanimously approved by voice vote.

The following proxy was in effect for the meeting – John Varnell for Tim Hall (see attachment).

Update on Action Items from February 5th Meeting

1) Task force members to contemplate the impacts to their respective companies as it relates to the various options for positioning new rate structure language into the tariff (e.g. all remain in 1A, only RS 1 remain in 1A, all in separate section). Members should be prepared to discuss at February 21st meeting.

   UPDATE: Discussed under Agenda Item 3.

2) Task force members to discuss within their respective companies the preference on removing/keeping a cap on the rate schedule(s). Members should be prepared to discuss at February 21st meeting.

   UPDATE: Discussed under Agenda Item 3.

3) Staff to incorporate illustrative timeline into the white paper to clearly explain the period for which billing determinants will be utilized in the annual rate setting process and the period for which the established rate would be in effect.

   UPDATE: Illustrative timeline was added to white paper (Agenda Item 4)

4) Staff to prepare formula templates for proposed rate schedules.

   UPDATE: This item remains open.

5) Staff to prepare analysis on monthly assessments illustrating materiality and the underlying components of the calculation

   UPDATE: Discussed under Agenda Item 3. Schedule was included in meeting materials.
   .

6) Staff to research current tariff language on bad debt, identifying exposure (if any) that would necessitate the inclusion of language in tariff sections under current revision.

   UPDATE: Discussed under Agenda Item 3. Memo was included in meeting materials.

Tariff Language Review

Mike Riley facilitated the ongoing review and edit of the proposed tariff language as provided in the meeting materials. The Task Force worked through each of the sections representing the four rate schedules, providing numerous edits. There were several items/issues raised during the February 5th meeting that required additional analysis and consideration. A recap of those issues along with the ultimate resolution reached during this meeting is as follows:

(1) **Rate Cap**
Issue: Current Schedule 1A explicitly sets a cap on the administrative fee that SPP can charge. Is a cap needed under the proposed new rate structure? At the conclusion of the February 5th meeting, Task Force members were asked to go back and discuss with their respective companies and be prepared to discuss at next meeting.

Resolution: After a moderate amount of discussion, there was general agreement that a) some type of cap should remain in the tariff for the proposed rate structure and b) a cap for each rate schedule did not seem like a reasonable option. Wes Berger made the following motion related to the rate cap -

"To retain the current administration cap in the tariff and develop a tab in the formula rate template that will duplicate the current methodology of calculating the 1A fee to compare the annual values to this cap."

Joel Dagerman seconded the motion. Staff expressed their concern with having a cap calculation that was disconnected from the rate setting calculations given the difference in the billing determinants utilized for each calculation. Rate cap calculation would be based on 12CP and proposed rate schedules 2-4 would be based on market billing determinants. Only rate schedule 1 is based on 12 CP. The motion passed by voice vote with MJMEUC abstaining.

(2) **Location of New Tariff Language**
Issue: How should the new rate schedules be incorporated in the tariff? Options include leaving all in Schedule 1A, moving all to new section, or leaving only RS 1 in Schedule 1A while including all others in a separate section (e.g. 13 or AE). Moving any or all language from Schedule 1A would necessitate some TOs to make new filings with FERC and possibly trigger state filings for other entities. During the February 5th meeting, Task Force members were asked to go back and discuss impacts with their respective companies and be prepared to discuss at next meeting.

Resolution: After a moderate amount of discussion, the Task Force agreed that the four proposed rate schedules should be retained within the current Schedule 1-A in some manner. Depending on further analysis of existing references in the tariff back to 1-A, it may make sense to create additional sections (B, C, and D) to accommodate the four rate schedules. In summary, the Task Force preferred that no new sections be created in the tariff for the four rate schedules (i.e. no Schedule 13 as previously proposed).

(3) **Bad Debt Expense Reference**
Issue: Current Schedule 1A includes language to address bad debt expense. Under the new proposed rate schedules, is this language still necessary? During the February 5th meeting, staff was asked to research and prepare analysis for next meeting.

Resolution: Dianne Branch provided an overview of the memo included in the meeting materials. In summary, current tariff language contains provisions to cover situations of non-payment for invoiced market and transmission activity. As described in the memo, situations that might give rise to bad debt expense in any given year would obviously impact the over/under recovery for that year and that impact would be included in the following year's rate setting calculation as an adjustment to the NRR. Therefore, it is staff's recommendation that there would be no special mention of bad debt expense in the tariff language supporting the new rate schedules given that it was really no different than any other variance to budget in a given year. While the Task Force agreed with staff's recommendation to exclude from tariff language, they suggested a line for bad debt expense be incorporated into the formula rate templates to cover any future situation where such expense would be a component of the annual rate true-up.

(4) **Monthly Assessments**
Issue: Under proposed new rate structure, should monthly assessments be eliminated? This current language resides in the by-laws and would require approval from the Corporate Governance Committee to remove. During the February 5th meeting, staff was asked to prepare analysis for next meeting.

Resolution: Dianne Branch provided an overview of the analysis performed by staff since the last meeting. The conclusion of the analysis was that there was no load billed under the current methodology as a monthly assessment that would not be picked up in the proposed methodology either under Rate Schedule 1 as a TSR or under Rate Schedules 3 and 4 as market activity. This conclusion was confirmed during the meeting by SPP Settlements staff member, David Daniels. The Task Force concluded that no further consideration was needed for monthly assessments in the tariff language supporting the proposed four rate schedule structure. However, it was suggested that current monthly assessment language in the by-laws be reviewed further as there may be a need to remove reference to the Schedule 1-A billing practices.

White Paper Review

The Task Force discussed the content of the white paper, identifying numerous items that need to be considered before the document can be finalized. Those items are summarized as follows:

1) Recent decisions made during this meeting need to be incorporated
2) MMU consultation and opinion should be more fully documented
3) Titles of rate schedules to be updated to match drafted tariff language
4) Transition/true-up processes should be more fully documented *
5) Language highlighting the correlation between Rate Schedule costs to FERC expense accounts should be added
6) Remove vote counts/dissent comments
7) Refine definition of TCR Holder to more closely align to proposed tariff language
8) Add the rate schedule summary slide from previous presentations that summarizes by rate schedule - costs to be recovered, who pays, billing determinants, etc.
9) Add language supporting the rationale as to the necessity for both Rate Schedule 3 and 4
10) Mention the decision to eliminate the virtual transactional fee charge.
11) Refine language in the Cash and Billing Determinant section to exclude some of the discussions leading up to the final conclusions reached

*A separate motion was made by Bob Tallman to include transition/true-up language in the white paper. Motion was seconded by Wes Berger. The motion passed unanimously by voice vote.

Action Items

1) Staff to prepare formula templates for proposed rate schedules.
2) Staff to incorporate recommended edits to the white paper draft.
3) Staff to complete tariff language edits as discussed during meeting

Future Meetings

Monday, March 25th 1AM-5PM – Teleconference/WebEx

There being no further business, John Olsen adjourned the meeting at 2:05 PM.

Respectfully Submitted,

Dianne Branch
Secretary

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE MEETING

February 21, 2019

DFW Hyatt Regency

• A G E N D A •

8AM – 2PM CST

1. Administrative Items (10 minutes)
   a. Call to Order…………………………………………………………………………...John Olsen
   b. Attendance……………………………………………………………………………...Dianne Branch
   c. Review of Agenda………………………………………………………………………John Olsen
   d. Approve Meeting Minutes………………………..………………………………John Olsen
2. Review of Past Actions Items (10 minutes)…………………………………………………..Dianne Branch
3. Tariff Language Review (180 minutes)…………..……………………………………………. Mike Riley
4. Whitepaper Review (60 minutes)……………………………………………..………………Dianne Branch
5. Outstanding Issues/Wrap-Up (30 minutes)………………………………..……………………John Olsen
6. Closing Items (10 minutes)……………………………………………. ……………………Dianne Branch
   a. Summary of Action Items
   b. Future meetings

SPP Southwest Power Pool

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE
DFW Hyatt Regency – Dallas, TX
February 21, 2019

• ATTENDANCE LIST •

Name	System
Dianne Branch	SPP
Mike Riley	SPP
Jason Mazigian	Basin Electric
Robert Tallman	OG&E
John Olsen	EVERGY
Ray Bergmeier	SEPC
Jim Jacoby	AEP
JOHN VARNELL	TENASKA
Wes Berger	Xcel Energy / SPS
David Mindham	ITC

Dianne Branch

From: Hall, Tim
Sent: Friday, February 15, 2019 1:38 PM
To: Olsen, John
Cc: Dianne Branch; Varnell, John
Subject: **External Email** 1ATF Proxy

John and Dianne, John Varnell will have my proxy at next week's 1ATF. I will be unable to participate due to prior commitments.

Thanks,

Tim Hall
Manager, Market Policy & Affairs
Southern Power
3535 Colonnade Parkway
Birmingham, AL 35243
Tel 205.992.0040
Mob 334.391.6206
Southern Power

Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

February 5, 2019

DFW Hyatt Regency – 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:

John Olsen	Evergy
Jim Jacoby	AEP-Public Service Company of Oklahoma
Jason Mazigian	Basin Electric
Greg Garst	OPPD
Alfred Busbee	GDS Associates/ETEC
John Varnell	Tenaska
Tim Hall	Southern Power
David Mindham	ITC Holdings Corp.
Wes Berger	Xcel Energy/SPS
Tom Dunn	SPP
Mike Riley	SPP
Dianne Branch	SPP

Those participating by phone were as follows:

Robert Tallman	OG&E
Joel Dagerman	NPPD
Heather Starnes	Healy Law Offices/MJMEUC
Rob Janssen	Dogwood Energy
Ray Bergmeier	Sunflower Electric
Chris Lyons	Customized Energy Solutions
David Erkin	AEP
David Kays	OG&E
Don Frerking	Evergy
Gary Hoffman	WAPA
Ishwar Saini	Macquarie Energy LLC
J.P. Maddock	Basin Electric
Jessica Meyer	Lincoln Electric System
Jessica Kasparek	Lincoln Electric System
Jill Jones	MEAN
Robert Pick	NPPD
Ronald Chartier	Sunflower Electric
Carrie Dixon	Xcel Energy
Shawnee Claiborn Pinto	Public Utility Commission of Texas
Richard Dillon	SPP
Scott Smith	SPP
Nicole Wagner	SPP
Lee Elliot	SPP
Patti Kelly	SPP

Minutes from the January 17, 2019 teleconference meeting were reviewed. Alfred Busbee motioned to approve the minutes. The motion was seconded by Jason Mazigian. The minutes were unanimously approved by voice vote.

Update on Action Items from January 17th Meeting

1 - Staff to prepare historical analysis of billing determinant data for the rate schedules to better understand seasonal fluctuations and other trends. Additionally, key dates/events impacting each billing determinant should be highlighted.

UPDATE: This item was covered under Agenda Item 3.

True-Up Cadence for Rate Schedules

Dianne Branch presented the results of staff's analysis of billing determinants for market based rate schedules (RS2-4). Staff examined the monthly billing determinant data using the following criteria –

1) 2015-2018 actual data
2) TCRs awarded and converted for Rate Schedule 2
3) Real time generation, load, import/export, and virtual energy for Rate Schedule 3
4) Real time generation, load, and import/export for Rate Schedule 4

Based on the analysis of monthly trend and rolling 12 month averages from 2015-18, staff summarized their observations as follows -

1) Rolling average for Schedule 3 and 4 billing determinants is relatively flat with only a modest rise over the 4 year period
2) Rolling average for Schedule 2 billing determinants is relatively flat with moderate rise beginning in late 2017 (likely due to increased congestion from wind, increase in financial only asset owners, etc.)

After staff's presentation, there was general discussion by the Task Force as to what the appropriate true-up frequency should be for the proposed rate schedules. Certain members thought that a more frequent true-up process made sense as it would more equitably match cost with those receiving benefit while others thought an annual true-up process would ensure that we achieve one of the overarching principles of keeping things simple. Following a fair amount of discussion on the subject, Jim Jacoby made a motion to approve an annual rate setting process for rates that would be in effect for the following calendar year and would be estimated based on billing determinants for previous 12 months (August-July to coincide with the timing of the budget preparation). David Mindham seconded the motion. The motion passed by voice vote with OG&E voting no. Heather Starnes suggested that a quarterly update be provided to the MOPC during the first year after implementation to get everyone comfortable with the new rate setting process. The update would provide a comparison of actual results to budget for both costs and billing determinants.

Tariff Language Review

Mike Riley facilitated the review and edit of the proposed tariff language as provided in the meeting materials. Mike started with a brief overview of the existing Schedule 1A tariff language and then introduced the separate document (Schedule 13) that contained the proposed language for the new rate schedules. The Task Force worked through each of the sections representing the four rate schedules, providing numerous edits and also identifying numerous issues, many of those requiring additional research and analysis. A summary of those issues is as follows:

1) **Rate Cap** - Current Schedule 1A explicitly sets a cap on the administrative fee that SPP can charge. Is a cap needed under the proposed new rate structure? Task Force members were asked to go back and discuss with their respective companies and be prepared to discuss at next meeting. See related action item in section below.

2) **Location of New Tariff Language** - How should the new rate schedules be incorporated in the tariff? Options include leaving all in Schedule 1A, moving all to new section, or leaving only RS 1 in Schedule 1A while including all others in a separate section (e.g. 13 or AE). Moving any or all language from Schedule 1A would necessitate some TOs to make new filings with FERC and possibly trigger state filings for other entities. Task Force members were asked to go back and discuss impacts with their respective companies and be prepared to discuss at next meeting. See related action item in section below.

3) **Bad Debt Expense Reference** – Current Schedule 1A includes language to address bad debt expense. Under the new proposed rate schedules, is this language still necessary? Staff to research and prepare analysis for next meeting. See related action item in section below.

4) **Transmission Service Request Charges** – Current Schedule 1A includes a provision for charging a fee ($100-$200) for each new transmission service request that is then subject to rebate once the transmission customer becomes legally obligated to pay for the applicable point to point service charge or if the requested point to point service is denied. Although this is not a significant source of revenue, the Task Force decided to keep this language in the tariff section describing the RS1 administrative charge.

5) **Monthly Assessments** – Under proposed new rate structure, should monthly assessments be eliminated? This current language resides in the by-laws and would require approval from the Corporate Governance Committee to remove. Staff to prepare analysis for next meeting. See related action item in section below.

6) **Virtual Fees** – Given that virtual participants will now be billed under proposed RS 3, should the $0.05 charge per bid be eliminated from Attachment AE? After some discussion, it was determined that the task force had not previously voted on this issue.

   Greg Garst made a motion to formally eliminate the $0.05 charge on virtual bids. Tim Hall seconded that motion. The motion passed by voice vote with NPPD and OG&E voting no. The following rationale was provided for the No votes:

   a. **NPPD** – Due to the de minimis nature of the charge, no additional change was warranted.
   b. **OG&E**- Virtuals have already been exempted from the majority of costs for the market services they use.

White Paper Review

Due to timing constraints and the desire to incorporate additional analysis and conclusions reached in this meeting, review and approval of the white paper was deferred until the February 21st meeting

Action Items

1) Task force members to contemplate the impacts to their respective companies as it relates to the various options for positioning new rate structure language into the tariff (e.g. all remain in 1A, only RS 1 remain in 1A, all in separate section). Members should be prepared to discuss at February 21st meeting.

2) Task force members to discuss within their respective companies the preference on removing/keeping a cap on the rate schedule(s). Members should be prepared to discuss at February 21st meeting.

3) Staff to incorporate illustrative timeline into the white paper to clearly explain the period for which billing determinants will be utilized in the annual rate setting process and the period for which the established rate would be in effect.

4) Staff to prepare formula templates for proposed rate schedules.

5) Staff to prepare analysis on monthly assessments illustrating materiality and the underlying components of the calculation.

6) Staff to research current tariff language on bad debt, identifying exposure (if any) that would necessitate the inclusion of language in tariff sections under current revision.

Future Meetings

Thursday, February 21st 8AM-2PM – DFW Hyatt Regency

There being no further business, John Olsen adjourned the meeting at 1:55 PM.

Respectfully Submitted,

Dianne Branch
Secretary

SCHEDULE 13

TARIFF ADMINISTRATIVE SERVICES

I. GENERAL

The Transmission Provider shall provide the administrative services described in this Schedule 13 to carry out its responsibilities under this Tariff. Transmission Customers and Market Participants must purchase these services from the Transmission Provider. In projecting and recovering its expenses, the Transmission Provider shall recover 100% of its total expenses not otherwise collected under this Tariff, through the charges described in this Schedule 13.

II. SCHEDULE 13-1 TRANSMISSION ~~SCHEDULING, SYSTEM CONTROL AND DISPATCH, AND RELIABILITY PLANNING~~ ADMINISTRATIVE SERVICE

Transmission ~~scheduling, system control and dispatch, and reliability planning~~ administrative service is provided by the Transmission Provider to all Transmission Customers under this Tariff~~. This service~~ and includes the provision of: (1) reliability coordination; (2) transmission scheduling; (~~2~~3) system control; ~~(3) dispatching;~~ and, (4) ~~system~~transmission planning services ("Schedule 13-1 Service").

A. SCHEDULE 13-1 SERVICE ~~CHARGE~~ RATE CALCULATION

The Schedule 13-1 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-1 Service.

1. Costs ~~to Be Recovered~~

The costs to be recovered under this Schedule 13-1 ~~in the monthly charges~~ include without limitation, any costs of direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-1 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-1 Service), and other costs associated with providing Schedule 13-1 Service ("Schedule 13-1 Costs").

2. Billing Determinants

~~Schedule 13-1 Costs are recovered by assessing~~

The Transmission Provider will determine the Schedule 13-1 billing determinants based on the Transmission Provider's budgeted and forecasted Point-to-Point Transmission Service and Network Integration Transmission Service~~. The billing determinant used for the Schedule 13-1 Service rate assessed to Point-To-Point Transmission Service is all capacity reserved by Transmission Customers. The billing determinant used for the Schedule 13-1 Service rate assessed to Network Integration Transmission Service is the 12 month average of the Transmission Customer's coincident Zonal Demands used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month. The charge per MW per hour shall be the same for Point-To-Point Transmission Service as for Network Integration Transmission Service.~~, to be billed in the next calendar year.

3. Rate Formula

Annually, the Transmission Provider ~~shall~~will determine the Schedule 13-1 Service rate for each calendar year by dividing the Transmission Provider's ~~projected~~budgeted Schedule 13-1 Costs, adjusted by any prior year under recovery or over recovery, by the ~~projected~~ Schedule 13-1 billing determinants ~~for that year~~described above. Notwithstanding the foregoing, the Transmission Provider may recalculate the Schedule 13-1 Service rate more frequently using the same methodology described herein in the event forecasted costs or billing determinants differ from those budgeted. Any such change will be approved by the Transmission Provider's Board of Directors.

B. SCHEDULE 13-1 CHARGES TO TRANSMISSION CUSTOMERS

~~For each month, the charges for~~The Schedule 13-1 rate is charged to all Transmission Customers ~~shall~~. The charge for Point-to-Point Transmission Service will be calculated by multiplying the effective Schedule 13-1 rate as determined above, by all of the Transmission Customer's ~~billing determinants in accordance with this Schedule 13-1.~~ reserved capacity per MWh. The charge for Network Integration Transmission Service will be calculated by multiplying the effective Schedule 13-1 rate as determined above, by the prior year calendar 12 month average of the

Transmission Customer's monthly Network Load used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month.

~~Transmission Service Request Charges:~~**III. TRANSMISSION SERVICE REQUEST CHARGES:**

The Transmission Customer shall pay the Transmission Provider a charge for each new Transmission Service Request as follows:

(i) For Firm Point-To-Point Transmission Service:

Reservations less than one month: $100

Reservations one month or longer: $200

(ii) For Non-Firm Point-To-Point Transmission Service:

Each Reservation: $0.

However, the Transmission Customer shall have this fee rebated to it once the Transmission Customer becomes legally obligated to pay the applicable Firm Point-To-Point Transmission Service charges under this Tariff or if the requested Firm Point-To-Point Transmission Service is denied by the Transmission Provider.

~~Bad Debt Expense:~~

~~The Transmission Provider shall include in its charges under this Schedule a component to cover estimated bad debts. The Transmission Provider shall reconcile actuals to estimates and shall adjust future monthly charges to reflect either over or under recoveries.~~

~~III~~IV. SCHEDULE 13-2 TRANSMISSION CONGESTION RIGHTS ADMINISTRATIVE SERVICE

Transmission Congestion Rights (“TCR”) administrative service is provided by the Transmission Provider to all Market Participants that ~~own Transmission Congestion Rights (“TCRs”)~~hold TCRs issued by the Transmission Provider through allocation, assignment, auction or any other process under this Tariff~~.~~ and that are settled by the Transmission Provider (“TCR ~~Owner~~Holder”). This service includes the provision of: (1) TCR administration through allocation, assignment, auction or any other process under this Tariff; (2) simultaneous feasibility tests and other applicable studies to determine the total TCRs that can be accommodated by the Transmission System; (3) TCR tools; ~~and,~~ (4) a secondary market for TCRs; and, (5) other processes contained in the Tariff that support the awarding of TCRs (“Schedule 13-2 Service”).

A. SCHEDULE 13-2 SERVICE CHARGE

The Schedule 13-2 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-2 Service.

1. Costs ~~to Be Recovered~~

The costs to be recovered under this Schedule 13-2 ~~in the weekly charges~~ include without limitation, any direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-2 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-2 Service), and all other costs associated with providing Schedule 13-2 Service (“Schedule 13-2 Costs”).

2. Billing Determinants

The Transmission Provider will determine the Schedule 13-2 billing determinant ~~for the Schedule 13-2 Service rate is the total~~based on the Transmission Provider’s forecasted amount of TCR volume in MWh for all TCR ~~Owners expressed in MWh. The total TCR volume is the sum of the hourly TCR MWh for each billing period~~Holders for the next calendar year.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-2 Service rate for each calendar year by dividing the Transmission Provider’s projected Schedule 13-2 Costs, adjusted by any prior year under recovery or over recovery, by the ~~projected Schedule 13-2 billing determinant for that year.~~Schedule 13-2 billing determinants described above. Notwithstanding the foregoing, the Transmission Provider may recalculate the Schedule 13-2 Service rate more frequently using the same methodology described herein in the event forecasted costs or billing determinants differ from those budgeted. Any such changes will be approved by the Transmission Provider's Board of Directors.

B. CHARGES TO ~~MARKET PARTICIPANTS~~TCR HOLDERS

~~For each week, the charges for Market Participants~~The Schedule 13-2 rate is charged to all TCR Holders. The charge will be calculated by multiplying the effective Schedule 13-2 Service rate as determined above by the ~~Market Participant~~TCR Holder's billing ~~determinant in accordance~~determinants consistent with this Schedule 13-2.

~~IV~~V. SCHEDULE 13-3 INTEGRATED MARKETPLACE CLEARING ADMINISTRATIVE SERVICE

Integrated Marketplace clearing administrative service is provided by the Transmission Provider to all Market Participants that participate in transactions pursuant to Attachment AE of this Tariff or an applicable Market Participant Service Agreement as contained in Attachment AH of this Tariff. This service includes the provision of: (1) market settlements; (2) credit evaluation and risk mitigation services; (3) market monitoring functions; (4) information technology support; and, (5) customer service ("Schedule 13-3 Service").

A. INTEGRATED MARKETPLACE CLEARING ADMINISTRATIVE SERVICE CHARGE

The Schedule 13-3 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-3 Service.

1. Costs ~~To Be Recovered~~

The costs to be recovered under this Schedule 13-3 include without limitation, any direct resources, corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-3 Service), and all other costs associated with providing Schedule 13-3 Service ("Schedule 13-3 Costs").

2. Billing Determinants

The Transmission Provider will determine the Schedule 13-3 billing determinants ~~for the Schedule 13-3 Service rate, as expressed in MWh are~~based on the Transmission Provider's forecasted MWh amounts for the next calendar year of: 1) all Real-Time asset energy injected into and withdrawn from the Transmission System by all Market Participants; 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time; and, (3) all cleared Virtual Energy Bids and all cleared Virtual Energy Offers.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-3 Service rate for each calendar year by dividing the Transmission Provider's projected Schedule 13-3 Costs, adjusted by any prior year under recovery or over recovery, by the ~~projected~~most recent Schedule 13-3 billing determinants ~~for that year~~described above. Notwithstanding the foregoing, the Transmission Provider may recalculate the Schedule 13-3 Service rate more frequently using the same methodology described herein in the event forecasted costs or billing determinants differ from those budgeted. Any such changes will be approved by the Transmission Provider's Board of Directors.

B. CHARGES TO MARKET PARTICIPANTS

~~For each week, the charges for~~The Schedule 13-3 rate is charged to all Market Participants. The charge will be calculated by multiplying the effective Schedule 13-3 Service rate as determined above by the Market Participant's billing determinants ~~in accordance~~consistent with this Schedule 13-3.

~~V~~VI. SCHEDULE 13-4 INTEGRATED MARKETPLACE FACILITATION ADMINISTRATIVE SERVICE

~~The~~ Integrated Marketplace facilitation administrative service is provided by the Transmission Provider to all Market Participants that participate in transactions, except for cleared Virtual Energy Bids and cleared Virtual Energy Offers, pursuant to Attachment AE of this Tariff or an applicable Market Participant Service Agreement as contained in Attachment AH of this

Tariff. This service includes the provision and operation of the: (1) Day-Ahead Market; (2) Real-Time Balancing Market; and, (3) Reliability Unit Commitment processes ("Schedule 13-4 Service").

A. INTEGRATED MARKETPLACE FACILITATION ADMINISTRATIVE SERVICE CHARGE

The Schedule 13-4 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-4 Service.

1. Costs ~~To Be Recovered~~

The costs to be recovered under this Schedule 13-4 include without limitation, any direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-4 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-4 Service), and other costs associated with providing Schedule 13-4 Service ("Schedule 13-4 Costs").

2. Billing Determinants

The Transmission Provider will determine the Schedule 13-4 billing determinants ~~for the Schedule 13-4 Service rate are~~based on the Transmission Provider's forecasted MWh amounts for the next calendar year of: 1) all Real-Time asset energy injected into and withdrawn from the Transmission System by all Market Participants; and, 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-4 Service rate for each calendar year by dividing the Transmission Provider's projected Schedule 13-4 Costs, adjusted by any prior year under recovery or over recovery, by the ~~projected~~most recent Schedule 13-4 billing determinants ~~for that year.~~described above. Notwithstanding the foregoing, the Transmission Provider may recalculate the Schedule 13-4 Service rate more frequently using the same methodology described herein in the event forecasted costs or billing determinants differ from those budgeted. Any such changes will be approved by the Transmission Provider's Board of Directors.

B. CHARGES TO MARKET PARTICIPANTS

~~For each week, the charges for~~The Schedule 13-4 rate is charged to all Market Participants. The charge will be calculated by multiplying the effective Schedule 13-4 Service rate as determined above by the Market Participant's billing determinants ~~in accordance~~consistent with this Schedule 13-4.

Document comparison by Workshare Compare on Friday, February 15, 2019 9:50:24 AM

Input:	
Document 1 ID	file://C:\Finance\1A Task Force\Schedule 13\SPP Schedule 13 TF 020519.docx
Description	SPP Schedule 13 TF 020519
Document 2 ID	file://C:\Finance\1A Task Force\Schedule 13\1_SPP Schedule 13 TF 022119.docx
Description	1_SPP Schedule 13 TF 022119
Rendering set	Standard

Legend:	
Insertion	
~~Deletion~~	
~~Moved from~~	
Moved to	
Style change	
Format change	
~~Moved deletion~~	
Inserted cell	
Deleted cell	
Moved cell	
Split/Merged cell	
Padding cell	

Statistics:	
	Count
Insertions	55
Deletions	52
Moved from	2
Moved to	2
Style change	0
Format changed	0
Total changes	111

SCHEDULE 13

TARIFF ADMINISTRATIVE SERVICES

I. GENERAL

The Transmission Provider shall provide the administrative services described in this Schedule 13 to carry out its responsibilities under this Tariff. Transmission Customers and Market Participants must purchase these services from the Transmission Provider. In projecting and recovering its expenses, the Transmission Provider shall recover 100% of its total expenses not otherwise collected under this Tariff, through the charges described in this Schedule 13.

II. SCHEDULE 13-1 TRANSMISSION ADMINISTRATIVE SERVICE

Transmission administrative service is provided by the Transmission Provider to all Transmission Customers under this Tariff and includes the provision of: (1) reliability coordination; (2) transmission scheduling; (3) system control; and,(4) transmission planning services ("Schedule 13-1 Service").

A. SCHEDULE 13-1 SERVICE RATE CALCULATION

The Schedule 13-1 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-1 Service.

1. Costs

The costs to be recovered under this Schedule 13-1 include without limitation, any costs of direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-1 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-1 Service), and other costs associated with providing Schedule 13-1 Service ("Schedule 13-1 Costs").

2. Billing Determinants

The Transmission Provider will determine the Schedule 13-1 billing determinants based on the Transmission Provider's budgeted and forecasted Point-to-Point Transmission Service and Network Integration Transmission Service, to be billed in the next calendar year.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-1 Service rate for each calendar year by dividing the Transmission Provider's budgeted Schedule 13-1 Costs, adjusted by any prior year under recovery or over recovery, by the Schedule 13-1 billing determinants described above. Notwithstanding the foregoing, the Transmission Provider may recalculate the Schedule 13-1 Service rate more frequently using the same methodology described herein in the event forecasted costs or billing determinants differ from those budgeted. Any such change will be approved by the Transmission Provider's Board of Directors.

B. SCHEDULE 13-1 CHARGES TO TRANSMISSION CUSTOMERS

The Schedule 13-1 rate is charged to all Transmission Customers. The charge for Point-to-Point Transmission Service will be calculated by multiplying the effective Schedule 13-1 rate as determined above, by all of the Transmission Customer's reserved capacity per MWh. The charge for Network Integration Transmission Service will be calculated by multiplying the effective Schedule 13-1 rate as determined above, by the prior year calendar 12 month average of the Transmission Customer's monthly Network Load used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month.

III. TRANSMISSION SERVICE REQUEST CHARGES:

The Transmission Customer shall pay the Transmission Provider a charge for each new Transmission Service Request as follows:

(i) For Firm Point-To-Point Transmission Service:

Reservations less than one month: $100

Reservations one month or longer: $200

(ii) For Non-Firm Point-To-Point Transmission Service:

Each Reservation: $0.

However, the Transmission Customer shall have this fee rebated to it once the Transmission Customer becomes legally obligated to pay the applicable Firm Point-To-Point Transmission Service charges under this Tariff or if the requested Firm Point-To-Point Transmission Service is denied by the Transmission Provider.

IV. SCHEDULE 13-2 TRANSMISSION CONGESTION RIGHTS ADMINISTRATIVE SERVICE

Transmission Congestion Rights ("TCR") administrative service is provided by the Transmission Provider to all Market Participants that hold TCRs issued by the Transmission Provider through allocation, assignment, auction or any other process under this Tariff and that are settled by the Transmission Provider ("TCR Holder"). This service includes the provision of: (1) TCR administration through allocation, assignment, auction or any other process under this Tariff; (2) simultaneous feasibility tests and other applicable studies to determine the total TCRs that can be accommodated by the Transmission System; (3) TCR tools; (4) a secondary market for TCRs; and, (5) other processes contained in the Tariff that support the awarding of TCRs ("Schedule 13-2 Service").

A. SCHEDULE 13-2 SERVICE CHARGE

The Schedule 13-2 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-2 Service.

1. Costs

The costs to be recovered under this Schedule 13-2 include without limitation, any direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-2 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-2 Service), and all other costs associated with providing Schedule 13-2 Service ("Schedule 13-2 Costs").

2. Billing Determinants

The Transmission Provider will determine the Schedule 13-2 billing determinant based on the Transmission Provider's forecasted amount of TCR volume in MWh for all TCR Holders for the next calendar year.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-2 Service rate for each calendar year by dividing the Transmission Provider's projected Schedule 13-2 Costs, adjusted by any prior year under recovery or over recovery, by the Schedule 13-2 billing determinants described above. Notwithstanding the foregoing, the Transmission Provider may recalculate the Schedule 13-2 Service rate more frequently using the same methodology described herein in the event forecasted costs or billing determinants differ from those budgeted. Any such changes will be approved by the Transmission Provider's Board of Directors.

B. CHARGES TO TCR HOLDERS

The Schedule 13-2 rate is charged to all TCR Holders. The charge will be calculated by multiplying the effective Schedule 13-2 Service rate as determined above by the TCR Holder's billing determinants consistent with this Schedule 13-2.

V. SCHEDULE 13-3 INTEGRATED MARKETPLACE CLEARING ADMINISTRATIVE SERVICE

Integrated Marketplace clearing administrative service is provided by the Transmission Provider to all Market Participants that participate in transactions pursuant to Attachment AE of this Tariff or an applicable Market Participant Service Agreement as contained in Attachment AH of this Tariff. This service includes the provision of: (1) market settlements; (2) credit evaluation and risk mitigation services; (3) market monitoring functions; (4) information technology support; and, (5) customer service ("Schedule 13-3 Service").

A. INTEGRATED MARKETPLACE CLEARING ADMINISTRATIVE SERVICE CHARGE

The Schedule 13-3 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-3 Service.

1. Costs

The costs to be recovered under this Schedule 13-3 include without limitation, any direct resources, corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-3 Service), and all other costs associated with providing Schedule 13-3 Service ("Schedule 13-3 Costs").

2. Billing Determinants

The Transmission Provider will determine the Schedule 13-3 billing determinants based on the Transmission Provider's forecasted MWh amounts for the next calendar year of: 1) all Real-Time asset energy injected into and withdrawn from the Transmission System by all Market Participants; 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time; and, (3) all cleared Virtual Energy Bids and all cleared Virtual Energy Offers.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-3 Service rate for each calendar year by dividing the Transmission Provider's projected Schedule 13-3 Costs, adjusted by any prior year under recovery or over recovery, by the most recent Schedule 13-3 billing determinants described above. Notwithstanding the foregoing, the Transmission Provider may recalculate the Schedule 13-3 Service rate more frequently using the same methodology described herein in the event forecasted costs or billing determinants differ from those budgeted. Any such changes will be approved by the Transmission Provider's Board of Directors.

B. CHARGES TO MARKET PARTICIPANTS

The Schedule 13-3 rate is charged to all Market Participants. The charge will be calculated by multiplying the effective Schedule 13-3 Service rate as determined above by the Market Participant's billing determinants consistent with this Schedule 13-3.

VI. SCHEDULE 13-4 INTEGRATED MARKETPLACE FACILITATION ADMINISTRATIVE SERVICE

Integrated Marketplace facilitation administrative service is provided by the Transmission Provider to all Market Participants that participate in transactions, except for cleared Virtual Energy Bids and cleared Virtual Energy Offers, pursuant to Attachment AE of this Tariff or an applicable Market Participant Service Agreement as contained in Attachment AH of this Tariff. This service includes the provision and operation of the: (1) Day-Ahead Market; (2) Real-Time Balancing Market; and, (3) Reliability Unit Commitment processes ("Schedule 13-4 Service").

A. INTEGRATED MARKETPLACE FACILITATION ADMINISTRATIVE SERVICE CHARGE

The Schedule 13-4 Service charge provides for the recovery of any costs incurred by the Transmission Provider in providing this Schedule 13-4 Service.

1. Costs

The costs to be recovered under this Schedule 13-4 include without limitation, any direct resources, system maintenance, debt service (including costs of financing capital purchases associated with providing Schedule 13-4 Service), corporate overhead (including a proportionate allocation of indirect costs associated with providing Schedule 13-4 Service), and other costs associated with providing Schedule 13-4 Service ("Schedule 13-4 Costs").

2. Billing Determinants

The Transmission Provider will determine the Schedule 13-4 billing determinants based on the Transmission Provider's forecasted MWh amounts for the next calendar year of: 1) all Real-Time asset energy injected into and withdrawn from the Transmission System by all Market Participants; and, 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time.

3. Rate Formula

Annually, the Transmission Provider will determine the Schedule 13-4 Service rate for each calendar year by dividing the Transmission Provider's projected Schedule 13-4 Costs, adjusted by any prior year under recovery or over recovery, by the most recent Schedule 13-4 billing determinants described above. Notwithstanding the foregoing, the Transmission Provider may recalculate the Schedule 13-4 Service rate more frequently using the same methodology described herein in the event forecasted costs or billing determinants differ from those budgeted. Any such changes will be approved by the Transmission Provider's Board of Directors.

B. CHARGES TO MARKET PARTICIPANTS

The Schedule 13-4 rate is charged to all Market Participants. The charge will be calculated by multiplying the effective Schedule 13-4 Service rate as determined above by the Market Participant's billing determinants consistent with this Schedule 13-4.

Memorandum

To: Schedule 1-A Task Force

From: Dianne Branch

CC: Tom Dunn

Date: February 13, 2019

Re: Bad Debt Expense Consideration

The purpose of this memo is to provide an overview of potential situations whereby SPP could incur bad debt expense and highlight its impact on the cost recovery process. This information is being provided to assist the Task Force in its efforts to determine what language for bad debt expense is needed, if any, in the tariff revisions associated with the proposed rate schedules.

Potential Areas of Bad Debt Expense

The following represents likely situations where bad debt expense could be incurred:

- **Unpaid Study Invoices –** Invoices are generally not significant as deposits are maintained to cover costs of performing the study. If an invoice had to be written off, the result would be to either reverse revenue previously recorded or recognize bad debt expense, either of which would impact the net over/under recovery for that year.

- **Withdrawal Obligation Invoices –** While the invoiced amount could potentially be significant, to the extent that collectability was deemed an issue, we would fully reserve the receivable. Since withdrawal obligations are intended to cover future outflows based on current obligations, there is no expense incurred or loss of revenue that would need to be recovered from the remaining customer base.

- **Unpaid Administrative Fees Associated w/Transmission Invoices –** Any reversal of revenue or incurrence of bad debt resulting from the non-collection of administrative fees associated with a transmission invoice would impact the net over/under recovery for that year. See section below for an expanded discussion of the current tariff language describing nonpayment of a transmission invoice.

- **Unpaid Administrative Fees Associated w/Market Based Invoices (FUTURE STATE)** - Any reversal of revenue or incurrence of bad debt resulting from the non-collection of administrative fees associated with a market based invoice would impact the net over/under recovery for the year. See section below for an expanded discussion of the current tariff language describing nonpayment of a market services invoice.

Non-Payment of Transmission Invoices

Tariff Language

Section V part D of Attachment L provides definitive guidance on procedures to be followed in the event of non-payment by a transmission customer. This includes procedures for notification, collection, reduced payouts to transmission owners, etc.

While the tariff does not specifically mention the recovery of administrative fees, there is mention of some cost recovery in Section V.D.2 –

> **"Any funds that are attributable to an Unpaid Obligation that are recovered by SPP subsequent to the ninety (90) day period after SPP declares the Unpaid Obligation pursuant to Section V.D.1 of this Attachment L, shall first be applied to satisfy outstanding costs of enforcement and collection of the Unpaid Obligation, and any other amount due to SPP under the Tariff or any other agreements."**

One could interpret that to encompass any administrative fees that SPP might be owed at the time the amounts are recovered. In summary, there is some exposure that the administrative fee portion of the monthly transmission service billing could be deemed uncollectible and ultimately give rise to the recording of bad debt expense.

Non-Payment of Market Invoices

Tariff Language

Section V part C of Attachment L provides definitive guidance on procedures to be followed in the event of non-payment by a market participant. This includes procedures for notification, collection, short-payments, uplifts, etc.

Unlike the section describing transmission related invoices, there is no mention of any recovered amounts being applied against outstanding costs of enforcement and collection of the Unpaid/Uncollectible Obligation, and any other amount due to SPP under the Tariff or any other agreements. The absence of language to that effect does not seem unreasonable given that historically there have been no administrative fees invoiced to the weekly market participants.

Staff Recommendation

Any event described in the preceding sections that would result in either the reversal of revenue or recognition of bad debt expense would impact the over/under recovery in the year reversed/recognized. It is current practice that the over/under recovery of costs for a given year will be included in the following year's rate setting calculation as an adjustment to the net revenue requirement(NRR). There are numerous factors and components that contribute to a net over/under recovery for any given year. The bad debt expense would just be one of those many items. Just as the current tariff language does not contemplate all the things that contribute to the over/under recovery, we do not believe that the proposed tariff language should specifically mention the inclusion of bad debt expense as a recoverable cost.

SPP does not currently record expense for estimated bad debt. Historically, collections have been high and losses associated with any uncollectible invoices have been insignificant. Additionally, the composition of costs that support the NRR for any given year includes many expenses, some known precisely and some estimated. Just as current Schedule 1A language does not prescribe every possible known and estimated expense that could be recovered under our tariff, we do not believe there should be special mention of bad debt expense (as a recoverable cost) in the tariff language supporting the new rate schedules

Admininstrative Fee Revenue Breakout
2015-2018

Service Type	2015			2016			2017			2018		
	MWh	$	%	MWh	$	%	MWh	$	%	MWh	$	%
Network	328,032	$ 127,932	87.9%	354,745	$ 131,256	92.1%	352,990	$ 147,903	90.3%	352,558	$ 151,247	91.7%
Point to Point	32,153	12,540	8.6%	32,015	11,846	8.3%	29,892	12,525	7.6%	28,224	12,108	7.3%
Monthly Assessment	13,094	5,106	3.5%	(1,636)	(605)	-0.4%	7,984	3,345	2.0%	3,755	1,611	1.0%
TOTAL	**373,278**	**$ 145,578**		**385,125**	**$ 142,496**		**390,865**	**$ 163,773**		**384,537**	**$ 164,967**	

DRAFT FORMULA FOR THE THREE MARKET BASED RATE SCHEDULES

Note: We will have one Charge Type (#RtSched13HrlyAmt $_{a,s,h}$) that represents the sum of the three rate amounts. The individual rates are calculated below in (a), (b), and (c). Market Participants will have all those fields/data provided as part of the bill determinant reports.

#RtSched13HrlyAmt $_{a,s,h}$ = **RtSched13Rate2HrlyAmt** $_{a,s,h}$ + **RtSched13Rate3HrlyAmt** $_{a,s,h}$ + **RtSched13Rate4HrlyAmt** $_{a,s,h}$

Where,

(a) **# RtSched13Rate2HrlyAmt** $_{a,s,h}$ = **RtSched13Rate2DlyRate** $_{d}$ * **RtSched13Rate2HrlyQty** $_{a,s,h}$

(a.1) **RtSched13Rate2HrlyQty** $_{a,s,h}$ = $\sum_{t}$**(TcrHrlyQty** $_{a,h,t}$**)**

(b) **# RtSched13Rate3HrlyAmt** $_{a,s,h}$ = **RtSched13Rate3DlyRate** $_{d}$ * **RtSched13Rate3HrlyQty** $_{a,s,h}$

(b.1) **RtSched13Rate3HrlyQty** $_{a,s,h}$ = **(**$\sum_{i}$**ABS (RtBillMtr5minQty** $_{a,s,i}$ + **RtBillMtrCir5minQty** $_{a,s,i}$**) / 12) +**

($\sum_{i}\sum_{t}$**[(ABS (RtImpExp5minQty** $_{a,s,i,t,rsg(null)}$**)/12)]) + (**$\sum_{t}$**ABS (DaClrdVHrlyQty** $_{a,s,h,t}$**))**

(c) **# RtSched13Rate4HrlyAmt** $_{a,s,h}$ = **RtSched13Rate4DlyRate** $_{d}$ * **RtSched13Rate4HrlyQty** $_{a,s,h}$

(c.1) **RtSched13Rate4HrlyQty** $_{a,s,h}$ = **(**$\sum_{i}$**ABS (RtBillMtr5minQty** $_{a,s,i}$ + **RtBillMtrCir5minQty** $_{a,s,i}$**) / 12) +**

($\sum_{i}\sum_{t}$**[(ABS (RtImpExp5minQty** $_{a,s,i,t,rsg(null)}$**)/12)])**

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

$$\textbf{RtSched13DlyAmt}_{\,a,\,s,\,d} = \sum_{h} \textbf{RtSched13HrlyAmt}_{\,a,\,s,\,h}$$

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

$$\textbf{RtSched13AoAmt}_{\,a,\,m,\,d} = \sum_{s} \textbf{RtSched13DlyAmt}_{\,a,\,s,\,d}$$

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

$$\textbf{RtSched13MpAmt}_{\,m,\,d} = \sum_{a} \textbf{RtSched13AoAmt}_{\,a,\,m,\,d}$$

2016-2018
Rate Schedule Analysis

Dollars in MMs	2016 RS 1	2016 RS 2	2016 RS 3	2016 RS 4	TOTAL	2017 RS 1	2017 RS 2	2017 RS 3	2017 RS 4	TOTAL	2018 RS 1	2018 RS 2	2018 RS 3	2018 RS 4	TOTAL	2019 RS 1	2019 RS 2	2019 RS 3	2019 RS 4	TOTAL
Budget																				
Budgeted NRR	$ 64.8	$ 4.0	$ 17.1	$ 64.6	$ 150.5	$ 65.5	$ 4.2	$ 18.1	$ 66.9	$ 154.6	$ 69.8	$ 4.4	$ 19.0	$ 72.3	$ 165.5	$ 73.0	$ 4.6	$ 20.0	$ 70.6	$ 168.2
PY Under/(Over) Recovery						$ (0.4)	$ 0.2	$ (2.1)	$ (7.2)	$ (9.6)	$ (1.2)	$ (1.1)	$ 0.8	$ 4.0	$ 2.5	$ (1.87)	$ (0.27)	$ (3.22)	$ (12.24)	$ (17.6)
Budgeted NRR (adjusted for PY Recovery)						$ 65.1	$ 4.3	$ 15.9	$ 59.7	$ 145.0	$ 68.6	$ 3.3	$ 19.8	$ 76.3	$ 168.0	$ 71.17	$ 4.35	$ 16.73	$ 58.35	$ 150.6
Budgeted Denominator (TWh)																				
12 CP	385.7					390.5					389.3					384.445				
TCR		467.0					460.6					485.9					622.94			
Virtual			16.3					20.2					30.5					38.27		
RT Energy			473.8	473.8				517.0	517.0				530.8	530.8				548.41	548.41	
	385.7	467.0	490.2	473.8		390.5	460.6	537.3	517.0		389.3	485.9	561.3	530.8		384.4	622.9	586.7	548.4	
Calculated Rates ($/MWh)	$ 0.168	$ 0.009	$ 0.035	$ 0.136		$ 0.167	$ 0.009	$ 0.030	$ 0.115		$ 0.176	$ 0.007	$ 0.035	$ 0.144		$ 0.185	$ 0.007	$ 0.029	$ 0.106	
% inc/(dec) from prior year rate						*-1%*	*11%*	*-15%*	*-15%*		*6%*	*-28%*	*19%*	*25%*		*5%*	*2%*	*-19%*	*-26%*	
Actuals																				
Actual Denominator (TWh)																				
12 CP	390.7					388.6					384.5									
TCR		452.5					546.8					648.0								
Virtual			24.1					34.6					38.4							
RT Energy			530.3	530.3				528.0	528.0				559.6	559.6						
	390.7	452.5	554.5	530.3		388.6	546.8	562.6	528.0		384.5	648.0	598.0	559.6						
% variance to budget	*1.3%*	*-3.1%*	*13.1%*	*11.9%*		*-0.5%*	*18.7%*	*4.7%*	*2.1%*		*-1.2%*	*33.4%*	*6.5%*	*5.4%*						
TOTAL Revenues	$ 65.6	$ 3.8	$ 19.4	$ 72.3	$ 161.2	$ 64.8	$ 5.1	$ 16.7	$ 60.9	$ 147.5	$ 67.7	$ 4.4	$ 21.1	$ 80.4	$ 173.7					
Actual NRR	$ 65.2	$ 4.0	$ 17.3	$ 65.1	$ 151.6	$ 63.5	$ 4.1	$ 17.5	$ 64.9	$ 150.0	$ 65.9	$ 4.1	$ 17.9	$ 68.2	$ 156.1					
% fav/(unfav) variance to budget	*-0.7%*	*-0.7%*	*-0.7%*	*-0.7%*		*2.4%*	*6.4%*	*-10.0%*	*-8.8%*		*4.0%*	*-25.3%*	*9.7%*	*10.6%*						
Over/(Under)	$ 0.4	$ (0.2)	$ 2.1	$ 7.2	**$ 9.6**	$ 1.2	$ 1.1	$ (0.8)	$ (4.0)	**$ (2.5)**	$ 1.9	$ 0.3	$ 3.2	$ 12.2	**$ 17.6**					

NOTE:

Schedule assumes that new rate structure was in effect as of January 1, 2016.

Budgeted denominator obtained from the August - July timeframe preceding the budget year. For example, determinants for the 2018 budget year represent the actual billing determinants from August 2016 -July 2017.

SCHEDULE 1A TASK FORCE WHITE PAPER

February 2019

Schedule 1A Task Force

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
1/29/2019	D.Branch	Initial Draft	
2/13/2019	D.Branch	Updates/Graph	

CONTENTS

SECTION 1: INTRODUCTION & BACKGROUND

SPP currently recovers the vast majority of its operating and capital costs from transmission customers who are taking service under the SPP tariff. This recovery approach was implemented when SPP solely provided transmission service under the SPP tariff. The SPP's operating and capital costs increased with the addition of the Energy Imbalance Services market in 2007 and again in 2014 with the implementation of the Integrated Marketplace. These increases in services and costs warrant a review of SPP's current cost recovery mechanism. There is a desire to have those who use and benefit from SPP's services help pay for those services.

The Schedule 1A Task Force (the "Task Force") was formed to develop a potential rate structure that would recover SPP's costs from the various users of SPP's services with the overarching principles of simplicity, better alignment of payer cost/benefit, and inclusion of energy transactions. The Task Force was comprised of the following members:

John Olsen, Evergy (Chair)
Joel Dagerman, Nebraska Public Power District
David Mindham, ITC Holdings Corp.
John Varnell, Tenaska
Rob Janssen, Dogwood Energy
Alfred Busbee, GDS Associates/ East Texas Electric Cooperatives
R.J. Tallman, Oklahoma Gas & Electric
Wes Berger, Southwestern Public Service Co.
Ray Bergmeier, Sunflower Electric Power Corporation
Greg Garst, Omaha Public Power District
Heather Starnes, Missouri Joint Municipal EUC
Tim Hall, Southern Power
Jason Mazigian, Basin Electric Power Cooperative
Jim Jacoby, American Electric Power-Public Service Company of Oklahoma

SECTION 2: PROCESS OVERVIEW

Before arriving at their final recommendation, the Task Force performed the following activities:

- Reviewed extensively SPP's cost in the FERC 668 reporting categories
- Examined RTO/ISO cost recovery methodologies for other regions
- Reviewed the current Schedule 1A billing processes

- Reviewed multiple iterations of strawman proposals (including staff whitepaper)
- Conducted multiple brain storming sessions on rate design
- Analyzed “cost shifts” between customer groups associated with proposed rate structures
- Reviewed cash flow analysis to assess impact of the proposed rate structures on SPP’s cash position throughout the year
- Consulted with SPP’s market monitor unit (MMU) to ascertain whether proposed changes would be problematic from a market monitor perspective

Early in the process, the Task Force agreed to use the cost reporting framework that followed the FERC’s requirement under Order 668. In summary, all operating costs would be evaluated in the categories that include FERC accounts 575.7 - Market Facilitation, Monitoring & Compliance; 561.4 - Scheduling, System Control & Dispatch; and 561.8 – Reliability Planning & Standards Development.

The Task Force quickly reached general agreement that the proposed structure should use a mix of demand and energy charges. The Task Force also reached general agreement that market costs should be recovered through energy charges and transmission planning costs should be recovered through demand charges. Additional discussions were necessary to determine the ultimate recommendation for 1) allocating Scheduling & Dispatch costs, 2) appropriate energy billing determinants, and 3) treatment of financial instruments (e.g. virtual transactions, TCRs).

After additional analyses and related discussions, the majority of the Task Force voted to 1) combine Scheduling & Dispatch costs with Reliability Planning and these will be part of the demand structure (similar to the current Schedule 1A billing practices); 2) include real time generation, load, and import/exports as energy billing determinants, 3) exclude day ahead market products; and 4) include TCRs and virtual transactions as billable transactions. Using these agreed upon concepts, the Task Force arrived at a four-part rate schedule cost recovery methodology summarized in the following section.

SECTION 3: OVERVIEW OF RATE SCHEDULES

RATE SCHEDULE #1 (RS 1) -

TRANSMISSION SCHEDULING, SYSTEM CONTROL AND DISPATCH, AND RELIABILITY PLANNING ADMINISTRATIVE SERVICE

RS 1 provides for the recovery of costs incurred by the Transmission Provider in providing scheduling, system control, dispatching, and system planning services. The costs to be recovered under RS 1 in the monthly charges include any costs of direct resources, system maintenance, debt service, corporate overhead, and other costs associated with administering this service.

RS 1 costs will be recovered by assessing customers who use Point-to-Point Transmission Service and Network Integration Transmission Service under the SPP tariff. The billing determinant used for this rate schedule assessed to Point-To-Point Transmission Service is all capacity reserved by the Transmission Customers. The billing determinant used for this rate schedule assessed to Network Integration Transmission Service is the 12 month average of the Transmission Customer's coincident Zonal Demands used to determine the Demand Charges under Schedule 9 multiplied by the number of all hours of the applicable month. The charge per MW per hour shall be the same for Point-To-Point Transmission Service as for Network Integration Transmission Service.

Below is an illustration of the calculation for RS 1 utilizing 2017 data for costs and 12CP estimate from the 2018 budget.

Rate Schedule #1		
Planning and Scheduling & Dispatch		
Reliability Planning	$21.6	MM
Scheduling & Dispatch	$42.3	MM
TOTAL COSTS	$64.0	
12CP Billing Determinants	382	TWh
Planning and Scheduling Rate	$0.167	/ MWh

<u>RS1 Voting Results</u>
For 10
Against 2
Abstain 2

<u>Dissenting Opinions</u>

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).

RATE SCHEDULE #2 (RS 2) -
TRANSMISSION CONGESTION RIGHTS ADMINISTRATIVE SERVICE

RS 2 provides for the recovery of any costs incurred by the Transmission Provider in providing 1) TCR administration through allocation, assignment, auction or any other process under this Tariff; 2) simultaneous feasibility tests and other applicable studies to determine the total TCRs that can be accommodated by the Transmission System; 3) TCR tools; and 4) a secondary market for TCRs. The costs to be recovered under RS 2 charges include any direct resources, system maintenance, debt service, corporate overhead, and all other costs associated with the Transmission Provider administering this service.

The billing determinant used for RS 2 is the total amount of TCR volume for all TCR Owners expressed in MWh. The total TCR volume is the sum of the hourly TCR MWh for each billing period.

Below is an illustration of the calculation for RS 2 utilizing 2017 data for costs and billing determinants:

Rate Schedule #2		
TCR Administration		
TCR Administration Costs	$4.4	MM
TCRs Awarded & Converted	547	TWh
TCR Administration Rate	$0.008	/ MWh

<u>RS 2 Voting Results</u>

For	11
Against	2
Abstain	1

<u>Dissenting Opinions</u>

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.

RATE SCHEDULE #3 (RS 3) -
INTEGRATED MARKETPLACE CLEARING ADMINISTRATIVE SERVICE

RS 3 provides for the recovery of costs incurred by the Transmission Provider in providing 1) market settlements; 2) credit evaluation and risk mitigation services; 3) market monitoring functions; 4) information technology support; and, 5) customer service. The costs to be recovered under RS 3 are any direct resources, corporate overhead, and all other costs associated with administering this service.

The billing determinants used for RS 3, as expressed in MWh are: 1) all Real-Time energy injected into and withdrawn from the Transmission System by all Market Participants; 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time; and, 3) all cleared Virtual Energy Bids and all cleared Virtual Energy Offers.

Below is an illustration of the calculation for RS 3 utilizing 2017 data for costs and billing determinants:

Rate Schedule #3		
Market Clearing		
Market Monitoring	$3.0	MM
Settlements	$2.8	MM
Information Technology (allocation)	$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

Due to the strong relationship between RS 3 and RS 4, one vote was held to accept/reject the schedules collectively. See voting results below the discussion of RS 4.

RATE SCHEDULE #4 (RS 4) -
INTEGRATED MARKETPLACE FACILITATION ADMINISTRATIVE SERVICE

RS 4 provides for the recovery of any costs incurred by the Transmission Provider in providing the 1) Day-Ahead Market; 2) Real-Time Balancing Market; and, 3) Reliability Unit Commitment Processes. The costs to be recovered under RS 4 include any direct resources, system maintenance, debt service, corporate overhead, and other costs associated with administering this service.

The billing determinants used for RS 4, as expressed in MWh, are: 1) all Real-Time energy injected into and withdrawn from the Transmission System and 2) all Import Interchange Transactions in Real-Time and all Export Interchange Transactions in Real-Time.

Below is an illustration of the calculation for RS 4 utilizing 2017 data for costs and billing determinants -

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

Due to the strong relationship between RS 3 and RS 4, one vote was held to accept/reject both schedules.

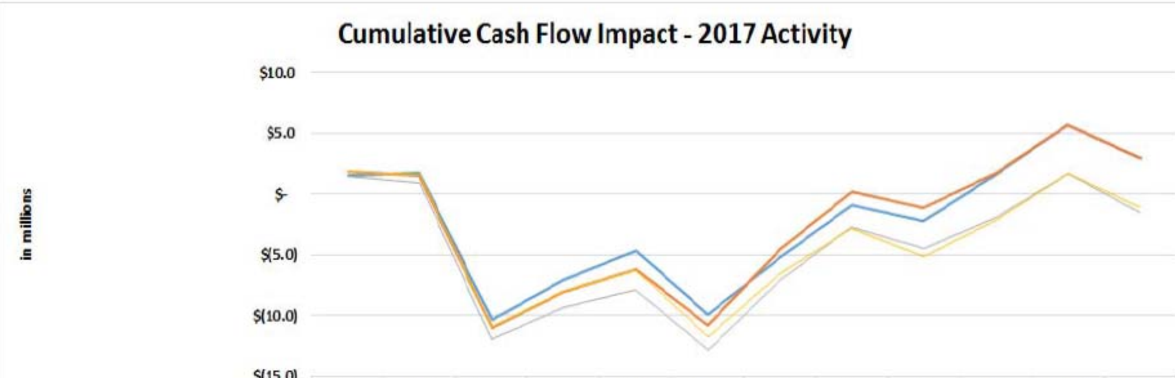
<u>RS 3 and 4 Voting Results</u>
For 10
Against 1
Abstain 1

<u>Dissenting Opinion</u>

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.

SECTION 4: CASH FLOW AND BILLING DETERMINANT ANALYSIS

Once the proposed rate structure was in place, staff performed a review of the impact that the new structure would have on our cash flows, including a sensitivity analysis to contemplate the impacts that fluctuations in billing metrics could have on cash flows. An exhibit from that analysis is presented below for illustrative purposes.



	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Actual Net Cash Flows	$1.5	$1.7	$(10.4)	$(7.1)	$(4.7)	$(10.0)	$(5.2)	$(0.9)	$(2.2)	$1.6	$5.7	$2.9
Proposed Rate Structure	$1.8	$1.5	$(11.0)	$(8.0)	$(6.2)	$(10.8)	$(4.6)	$0.2	$(1.2)	$1.7	$5.6	$2.9
Proposed w/ 5% decrease	$1.4	$0.8	$(12.0)	$(9.4)	$(7.9)	$(12.9)	$(7.1)	$(2.8)	$(4.5)	$(1.9)	$1.6	$(1.5)
Proposed w/ 5% decrease in June-Sept	$1.8	$1.5	$(11.0)	$(8.0)	$(6.2)	$(11.8)	$(6.6)	$(2.8)	$(5.1)	$(2.2)	$1.7	$(1.1)

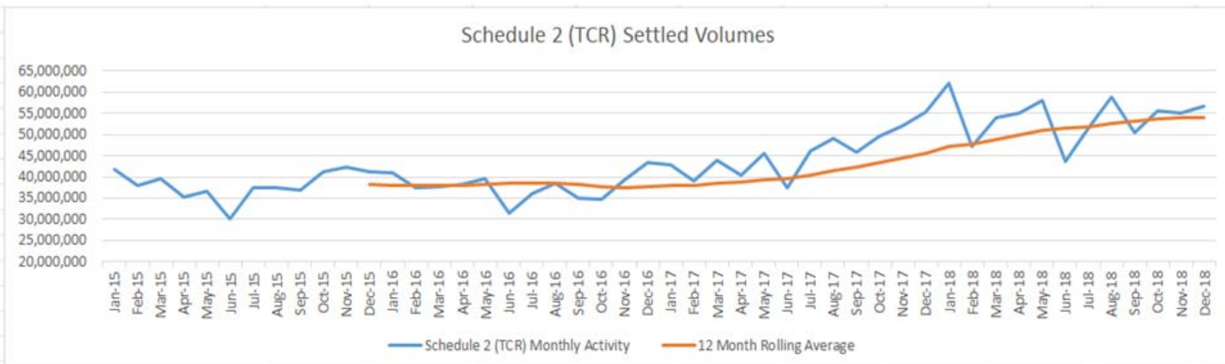
Staff concluded their analysis of the cash flows with the following observations:

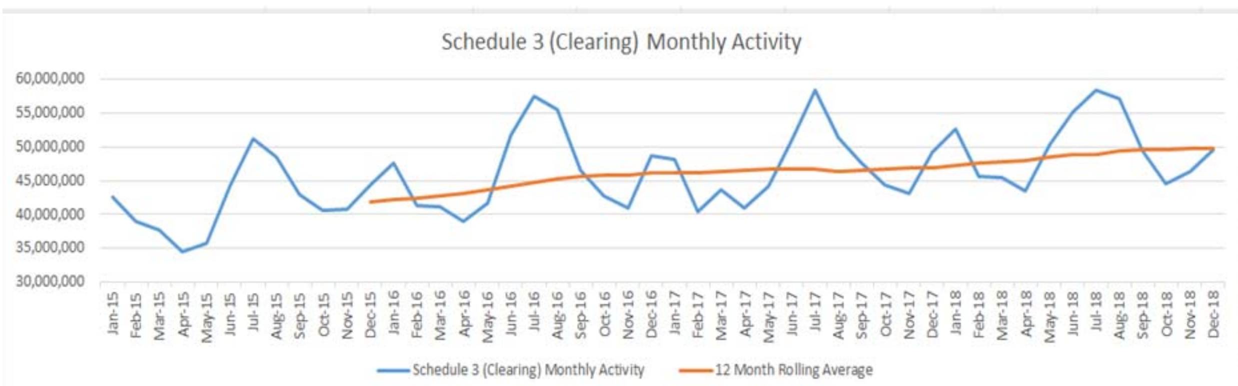
1) Seasonality in cash outflows exist today with notable spikes at quarter end (primarily due to debt payments)
2) Seasonal cash flow decreases noted in the periods examined are representative of historical trends
3) Cash flow position under proposed scenarios does not materially improve or worsen in comparison to actual results under current Schedule 1A methodology
4) Consistent with current practices, seasonal spikes can be managed with existing, short term financing arrangements
5) A net cumulative cash flow impact reaching negative $15.0 MM would create actionable concern and that it would take a 10% annual decrease in billing determinants to get close to that $15.0MM threshold in the periods examined in this analysis.

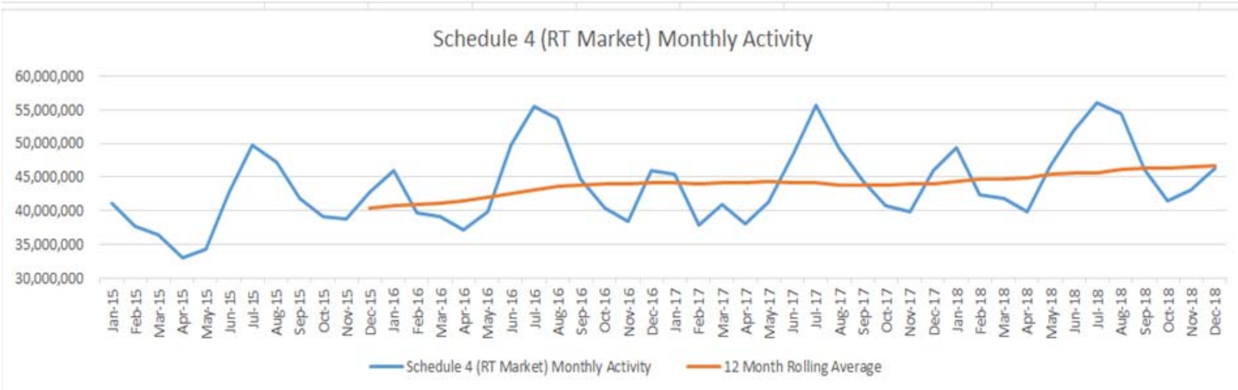
Recognizing that volatility of billing determinants could have an impact on over/under recovery, the Task Force also reviewed monthly billing determinant data for the market based rate schedules (RS2-4) using the following criteria –

1) 2015-2018 actual data
2) TCRs awarded and converted for RS 2
3) Real time generation, load, import/export, and virtual energy for RS 3
4) Real time generation, load, and import/export for RS 4

Exhibits from staff analysis are presented below for illustrative purposes-







Based on the analysis of monthly trending and the rolling 12 month average from 2015-18, staff summarized their observations as follows -

1) Rolling average for Schedule 3 and 4 billing determinants is relatively flat with only a modest rise over the 4 year period
2) Rolling average for Schedule 2 billing determinants is relatively flat with moderate rise beginning in late 2017 (likely due to increased congestion from wind, increase in financial only asset owners, etc.)

Taking into consideration both the cash flow analysis and billing determinant trend information, the Task Force debated the appropriate true-up frequency for the proposed rate schedules. Certain members thought that a more frequent true-up process (e.g. monthly, quarterly) made sense as it would more equitably match cost with those receiving benefit while other members thought an annual true-up process would ensure that we adhere to one of the overarching principles of keeping things simple. Ultimately the Task Force approved an annual rate setting process for rates that would be in effect for the following calendar year. Rates would be estimated based on actual billing determinants for the previous 12 months (August-July to coincide with the timing of the budget preparation for the following calendar year). The chart below illustrates the time period utilized for estimating the billing determinants in relationship to the timing of the rate setting process and actual billing period.

Process for Setting Rate for Calendar Year 3

Year 1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year 2	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Year 3	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
								Aug	Sep	Oct		

Billing Determinant Period Utilized for Rate Setting (Year 1 Aug – Year 2 Jul)
Rate Setting Occurs During Annual Budget Process (Year 2 Aug – Oct)
Billing Period for Calculated Rate (Year 3 Jan – Dec)
Rate Setting for Subsequent Year - True Up Consideration (Year 3 Aug – Oct)

SECTION 5: CONCLUSION

SPP's current administrative fee structure was established when SPP first provided transmission service under its tariff in 1998 and obviously never contemplated the additional energy market services currently provided. The overarching principles guiding the Task Force since its inception was to develop a rate structure that was simple to implement/administer, provided better alignment of beneficiary with payer, and included energy transactions. The Task Force carefully researched and evaluated the costs comprising SPP's administrative fee in relationship to our required reporting under FERC Order 668, considered the structure and methodology utilized by other RTO/ISOs, and deliberately examined the services provided by SPP through the lens of the beneficiary versus payer. Through much analysis and spirited debate, the Task Force has agreed upon a four-rate schedule cost recovery methodology described in detail in this document. This proposed methodology allocates a proportionate share of recoverable costs to our market participants including financial only entities. Additionally, staff believes that the current proposed structure will not translate to any material system or staffing costs to implement/administer. In conclusion, the Task Force recommends the four-rate schedule cost recovery methodology as described in this document for further consideration/approval by all relevant governing bodies to move forward with all activities necessary for full implementation.