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

Dianne Branch

From: Bergmeier, Ray
Sent: Tuesday, November 20, 2018 2:46 PM
To: Dianne Branch
Cc: Olsen, John; Bieker, Jeff
Subject: **External Email** Nov. 27 1ATF - Ray Proxy

Dianne,

Jeff Bieker will have my proxy for the Nov. 27th S1ATF meeting. Thanks.

Ray Bergmeier | Manager, Transmission Policy Affairs
Sunflower Electric Power Corporation | PO Box 1020, Hays, Kansas 67601-1020
O 785.623.3317 C 620-290-9831| RBergmeier@sunflower.net

Dianne Branch

From: Mindham David
Sent: Monday, November 26, 2018 6:55 AM
To: Dianne Branch; Olsen, John
Cc: Hall, Tim
Subject: **External Email** 1A Proxy

John and Dianne,

Something came up and I cannot attend the meeting tomorrow. I would like to give my proxy to Tim Hall.
Thank you.

David Mindham
ITC Holdings Corp. | 27175 Energy Way, Novi, MI 48377
Office: (248) 946-3278 | Cell: (608) 443-8648

Dianne Branch

From:	Dagerman, Joel
Sent:	Tuesday, November 27, 2018 1:24 PM
To:	Olsen, John
Cc:	Dianne Branch
Subject:	**External Email** RE: SPP 1A Meeting 11/27

At 1:30 PM, I have to exit the Sched 1A TF meeting. I will assign my proxy to the Chair.

From: John Olsen
Sent: Wednesday, November 21, 2018 11:08 AM
To: Dagerman, Joel L.
Cc: Dianne Branch (SPP)
Subject: RE: SPP 1A Meeting 11/27

This email is from John.Olsen@westarenergy.com. Do you know them and are you expecting this? - Look again!
Use the "Report Phishing" button if you think this is a phishing email.
Phishing is the #1 threat to NPPD. You are our best defense!!
Stay Vigilant!

Thanks,

John Olsen
Sr. Dir, DSO and Emergency Ops

From: Dagerman, Joel L. <jldager@nppd.com>
Sent: Wednesday, November 21, 2018 8:04 AM
To: John Olsen <John.Olsen@westarenergy.com>
Subject: SPP 1A Meeting 11/27

This is an EXTERNAL EMAIL. Stop and think before clicking a link, opening attachments or entering credentials.

Unfortunately, I will not be able to make it to Dallas for Tuesday's meeting. I see that there will be teleconference number now. 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.

Dianne Branch

From: Hall, Tim
Sent: Tuesday, November 27, 2018 1:10 PM
To: Olsen, John; Dianne Branch
Subject: **External Email** Fwd: 1A Proxy
Attachments: image001.gif

FYI

From: Rob Janssen

Sent: Tuesday, November 27, 2018 12:35 PM

To: Hall, Tim A. (SPC)

Subject: Re: 1A Proxy

This email has been sent from an external address. Please use caution when clicking on links or opening attachments.

Sure. Not a problem.

On Tue, Nov 27, 2018 at 1:24 PM Hall, Tim A. (SPC) <TIMHALL@southernco.com> wrote:

> Rob – had a slight emergency come up and having to run to the dentist in about 30 minutes…I had a filling fall out and it's just a little painful. Would you mind taking my proxy? Thanks!
>
> As an FYI, I'm also holding David Mindham's (ITC) proxy and I've let him know I'll be unavailable for most of the afternoon. I'm unsure if he'll reach out to you or someone else. I have not yet heard back from him.
>
> Thanks,
>
> **Tim Hall**
>
> Southern Power
>
> 3535 Colonnade Parkway
>
> Birmingham, AL 35243

BIN S-950-EC

Tel 205.992.0040

Mob 334.391.6206

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Dogwood Energy

6700 Alexander Bell Drive, Suite 360

Columbia, MD 21046

443-542-5125

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE MEETING

November 27, 2018

AEP Offices – Dallas, TX

• A G E N D A •

8AM – 3PM 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. RTO/ISO TCR Rate Comparison (15 minutes)…………………………… …………….Dianne Branch
4. Discussion on Proposed Rate Schedules (240 minutes)…………………...……………….John Olsen
5. Discussion on True-Up Cadence for Rate Schedules (60 minutes) …………………… John Olsen
6. Closing Items (10 minutes)…………………………………………. ……………………Dianne Branch
   a. Summary of Action Items
   b. Future meetings

Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

November 9, 2018

Teleconference

• M I N U T E S •

Administrative Items

Chair John Olsen called the meeting to order at 10:00 AM. The following individuals participated in the meeting:

John Olsen	Evergy
Jason Mazigian	Basin Electric
David Mindham	ITC Holdings
Tim Hall	Southern Power
John Varnell	Tenaska
Robert Tallman	OG&E
Wes Berger	SPS/Xcel Energy
Greg Garst	OPPD
Heather Starnes	Missouri Joint Municipal Elec Utility Commission
Alfred Busbee	GDS Associates/ETEC
Joel Dagerman	NPPD
David Erkin	AEP
Dennis Reed	Midwest Regulatory Consulting, LLC
Chris Lyons	Customized Energy Solutions
Christi Nicolay	Macquarie Energy, LLC
Don Frerking	Evergy
Seth Cochran	DC Energy
Mike Riley	SPP
Scott Smith	SPP
Patti Kelly	SPP
Brent Wilcox	SPP
Steve Davis	SPP
David Daniels	SPP
Ty Mitchell	SPP
Micha Bailey	SPP
Zeynep Vural	SPP
Dianne Branch	SPP

Minutes from the October 15, 2018 meeting were reviewed. Jason Mazigian motioned to approve the minutes. The motion was seconded by Greg Garst. The minutes were unanimously approved by voice vote.

The following proxies were in effect for the meeting – Heather Starnes for Rob Janssen, David Erkin for Jim Jacoby, and Dennis Reed for Ray Bergmeier (see attachments).

Update on Action Items from 10/15/18 Meeting

Action items resulted primarily from the discussion of the various market charge types and are summarized below by charge type.

Import Export Schedules

- **Action Item 1** – Further investigate how dynamic schedules are settled within the import/export charge types.

  UPDATE: In summary, David Daniels (SPP Settlements) explained that dynamic schedules are processed through settlements the same as all other import/export tags. The tag is updated via WebTrans and the updated quantity is sent and processed through settlements.

Demand Response

- **Action Item 2** – Further investigate how demand response should be used to allocate SPP Costs. Additionally, determine whether the MWhs would also be recognized in RT generation or RT load.

  UPDATE: In summary, David Daniels indicated that any demand response would be recognized under generation/load meter submittal.

Virtual Energy

- **Action Item 3a -** Investigate and report on how other RTOs (PJM, MISO, ISO-NE) charge market participants for virtual transactions. Are they allocated based upon MWhs or bid/offer submission? Submitted and/or cleared?

  UPDATE: Mike Riley provided an update under agenda item #3.

- **Action Item 3b -** What is the basis of the other RTOs' charge for virtual fees (i.e. is it cost based or only recovering for incremental activity?)

  UPDATE: Slide summarizing this data was included in the published materials and was presented after Mike Riley's update in agenda item #3.

- **Action Item 3c -** What is SPP's cost for supporting the virtual market?

  UPDATE: Staff reported there are no identifiable, incremental costs that can be uniquely associated with facilitating the virtual markets.

- **Action Item 3d -** What are the annual MWhs and bid/offer submissions volumes associated with virtual transactions (cleared and submitted)?

  UPDATE: Slide summarizing this data was included in the published materials and was presented during the discussion of agenda item #5.

Operating Reserves

- **Action Item 4 -** Verify that operating reserves would not be double-charged when deployed (i.e. also in RT generation).

  UPDATE: Given the task force had previously voted to exclude any determinant related to operating reserves, the answer to this question was deemed no longer relevant.

Transmission Congestion Rights/Auction Revenue Rights

- **Action Item 5 -** Provide additional analysis on possible TCR allocations. Analysis should include SPP's TCR costs, including overheads, and different scenarios of ARR and TCR combinations. Additionally, the following data should be quantified- number and MWhs for submitted TCRs and MWhs only for cleared TCRs.

  UPDATE: Slide summarizing this data was included in the published materials and was presented during the discussion of agenda item #5.

Update on RTO/ISO Filings for Virtual Rates

Mike Riley provided an overview of the initial filings for PJM, MISO, and ISO-NE relative to their virtual energy market. Mike highlighted pertinent facts associated with their filings as well as made special mention of any noteworthy considerations that ultimately supported the proposed methodology. Dianne Branch then walked through the specifics of the rate mechanisms utilized by each of the three entities to recover costs associated with virtual transactions, including the current rates being charged by each entity. There was a brief discussion and some general questions that were addressed by staff.

Q & A on Expenses by FERC Category

Dianne Branch provided general comments regarding the exhibit included with the meeting materials, which provided more granular detail for the expense components underlying each prescribed FERC reporting category. There were a few general questions regarding the schedule that were addressed by SPP staff.

Discussion on Virtuals/TCRs

Bid/offer metrics for TCR and Virtual activity were reviewed by the task force. Questions around the underlying assumptions for the metrics were fielded by SPP staff. There was a lengthy discussion on 1)various possibilities for allocating the TCR costs (as summarized in separate meeting exhibit) utilizing the numerous metrics provided as well as 2) the merit of charging virtual participants based on either a submitted and/or cleared, transactional/ volume basis. No firm decision was made on either TCR or Virtual transactions.

Action Items

1- Staff to prepare strawman proposals for allocating administrative costs, incorporating assumptions agreed upon in previous task force meetings. Proposals should include a separate charge for the recovery of TCR costs.

2- Staff to prepare a comparative analysis of TCR costs as recovered by other RTO/ISOs.

Future Meetings

Tuesday, November 27th 8AM-3PM – Dallas, TX   AEP
Tuesday, December 18th 1-4PM - Teleconference

There being no further business, John Olsen adjourned the meeting at 12:00 PM.

Respectfully Submitted,

Dianne Branch
Secretary

Southwest Power Pool

TCR Rate Comparisons

November 27, 2018

1A Task Force – Dallas, TX

SouthwestPowerPool

SPPorg

southwest-power-pool

	Separate Rate	Per Bid Charge	Per Bid Rate	MWh Charge	MWh Rate	Additional Information
MISO	No	N/A	N/A	Yes	$0.0034/MWh	**Schedule 16** -Rate is applied to FTR Holders' total FTR volume for that month, expressed in MWh. Includes those FTRs obtained through allocation, assignment, or auction. -Rate is recalculated monthly. Rate presented here is as of the October 2018 forecast.
PJM	Yes	Yes	$.0019/ bid hour submitted	Yes	$0.0028/FTR MWh	**Rate Schedule 9-2** - Per bid rate is calculated as follows (# of hours in all bids to buy FTR Obligations submitted by each MP during the month) +(5* # of hours in all bids to buy FTR Options submitted by each MP during the month). This applies to the Annual and Monthly Auctions -Rates are updated annually based on budgeted costs, forecast FTR MWh and FTR bid/offer hours - Rates presented here are the current 2018 published rates
ISO-NE	Yes	Yes	$2.18184 per submitted FTR bid $2.30577 per cleared FTR bid	No	N/A	**Rate Schedule 2** -Rates for FTRs were introduced in 2007 and have been updated every year since. - Rates presented here are the current 2018 published rates
NYISO	No	N/A	N/A	Yes	$0.0132/MWh	**Schedule 6.1.2.4.2** -Rate is applied to total settled Transmission Congestion Contracts (TCC) in MWhs - Rate is recalculated annually based on (revenue requirement + over/under collection) /3 year rolling average of billing units
CAISO	Yes	Yes	$1.00/bid	Yes	$0.0038/MWh	**Section 11.22** -CRR Transaction Fee – $1.00 per submitted CRR allocation nomination or CRR auction bid. -CRR Service Charge - Is applied to each scheduling coordinator's total MW holdings of CRRs that are applicable to each hour -Rates presented here are the current 2018 published rates -Rates are recalculated annually based on budgeted costs, estimated billing units, and prior year under/over recovery

Proposed Rate Schedules

November 27, 2018

1A Task Force - Dallas, TX

SouthwestPowerPool SPPorg southwest-power-pool

Overview

	Rate Schedule #1 Planning		Rate Schedule #2 TCR Admin		Rate Schedule #3 Market Clearing		Rate Schedule #4 Scheduling	
Total Costs	$21.6	MM	$4.4	MM	$14.2	MM	$111.3	MM
Denominator	382	TWh	547	TWh	563	TWh	528	TWh
Rate	$0.057	/ MWh	$0.008	/ MWh	$0.025	/ MWh	$0.211	/ MWh

NOTES:

- 2017 actual results were utilized for Total Costs in this analysis in order to provide a comparative basis when analyzing the true cost shift from our current method
- 12CP Data (utilized for Rate Schedule 1) represents the estimate from the 2018 budget.
- - Market metrics (utilized for Rate Schedules 2-4) were taken from the 2017 actual results as reported by settlements.

SPP

Rate Schedule 1- Planning

Rate Schedule #1		
Planning		
Reliability Planning	$21.6	MM
12CP Billing Determinants	382	TWh
Planning Rate	$0.057	/ MWh

SPP

Rate Schedule 2- TCRs

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

SPP

Rate Schedule 3- Market Clearing

Rate Schedule #3		
Market Clearing		
Market Monitoring	$3.0	MM
Settlements	$2.8	MM
Credit	$0.7	MM
Customer Relations (allocation)	$0.9	MM
Clearing Overhead	$6.9	MM
Market Clearing Costs	$14.2	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	$0.025	/ MWh

SPP

Rate Schedule 4- Mkt & Scheduling

Rate Schedule #4		
Mkt Faciliation & Scheduling		
Market Facilitation	$87.6	MM
Scheduling & Dispatch	$42.3	MM
Less: TCR Admin Costs	($4.4)	MM
Less: Market Clearing Costs	($14.2)	MM
Mkt Facilitation & Scheduling Costs	$111.3	MM
Real Time Generation	260	TWh
Real Time Load	250	TWh
Real Time Import/Export	18	TWh
Real Time Market Denominator	528	TWh
Market Facilitation & Scheduling Rate	$0.211	/ MWh

New Rate Schedule – By Entity

(All Dollars in MMs)

Entity Type	Rate Schedule #1 Planning	Rate Schedule #2 TCR Admin	Rate Schedule #3 Market Clearing	Rate Schedule #4 Markets & Scheduling	TOTAL
Cooperatives	$4.0	$0.2	$2.0	$16.5	$22.6
Federal Agencies	$0.6	$0.0	$0.4	$3.6	$4.6
Independent Power Producers	$1.2	$0.2	$0.9	$7.0	$9.3
Investor-Owned	$11.6	$1.2	$7.4	$62.2	$82.4
Marketers	$0.3	$2.2	$0.9	$0.7	$4.1
Municiples/State Agencies	$4.1	$0.4	$2.6	$21.5	$28.6
TOTAL	**$21.8**	**$4.3**	**$14.1**	**$111.5**	**$151.6**

SPP

Current vs New Rate Schedules

(All Dollars in MMs)

	Current Method	New Schedules	New vs Current	New vs Current
Entity Type	2017 Schedule 1A Fees	TOTAL	Inc/(Dec) $s	Inc/(Dec) %
Cooperatives	$28.8	$22.6	($6.2)	-21%
Federal Agencies	$4.3	$4.6	$0.3	6%
Independent Power Producers	$6.4	$9.3	$2.9	45%
Investor-Owned	$82.8	$82.4	($0.4)	0%
Marketers	$0.7	$4.1	$3.4	486%
Municiples/State Agencies	$28.5	$28.6	$0.0	0%
TOTAL	**$151.6**	**$151.6**	**$0.0**	

SPP

Current vs New Rate Schedules

(All Dollars in MMs)

Entity Type	Current Method 2017 Schedule 1A Fees	Current Method % of Total	New Schedules TOTAL	New Schedules % of Total	% Inc/(Dec)
Cooperatives	$28.8	19%	$22.6	15%	-4%
Federal Agencies	$4.3	3%	$4.6	3%	0%
Independent Power Producers	$6.4	4%	$9.3	6%	2%
Investor-Owned	$82.8	55%	$82.4	54%	0%
Marketers	$0.7	0%	$4.1	3%	2%
Municiples/State Agencies	$28.5	19%	$28.6	19%	0%
TOTAL	**$151.6**	**100%**	**$151.6**	**100%**	**0%**