Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

September 6, 2018

DFW Hyatt Regency – Dallas, Texas

• 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
Alfred Busbee	GDS Associates/ETEC
Jason Mazigian	Basin Electric
David Mindham	ITC Holdings
John Varnell	Tenaska
Ray Bergmeier	Sunflower Electric
Robert Tallman	OG&E
Rob Janssen	Dogwood Energy
Wes Berger	SPS/Xcel Energy
Greg Garst	OPPD
Joel Dagerman	NPPD
David Erkin	AEP
Carl Monroe	SPP
Mike Riley	SPP
Dianne Branch	SPP

Those participating by phone were as follows:

Heather Starnes	Missouri Joint Municipal Electric Utility Commission
Chris Lyons	Customized Energy Solutions
Jill Jones	MEAN
Aaron Pupa	LS Power
Brent Wilcox	SPP
Steve Davis	SPP
Scott Smith	SPP
Patti Kelly	SPP

Minutes from the August 24, 2018 meeting were reviewed. Jason Mazigian motioned to approve the minutes. The motion was seconded by Joel Dagerman. The minutes were unanimously approved by voice vote.

The following proxies were in effect for the meeting – Rob Janssen for Tim Hall and David Erkin for Jim Jacoby (see attachments).

Review of Analysis Requested from 8/24 Teleconference

- *Discussion on Schedule 1A Billing Overview*

  Dianne Branch provided an overview of the three components of the Schedule 1A fees as billed today. There was a moderate amount of discussion and questions on the grandfathered agreements, monthly assessments (specifically the origins of this billing component), etc. that were addressed by SPP staff.

- *Discussion on Generation Capacity Analysis*

  Scott Smith provided an overview of the underlying analysis performed in preparing the graphs presented in the materials and fielded general questions from the task force.

  Action Item – SPP staff to confirm the following -
    - Could the administrative fee be pass through in mitigated offers if generators are assessed a portion of the fee? (to be confirmed with Market Monitor)

- *Discussion on 3 Year Market Transaction Analysis*

  Dianne Branch presented the schedule summarizing billable units by various components of market services. There was a moderate amount of discussion on the various elements included in this analysis with particular emphasis on the TCRs and ARRs. There was concern raised that any allocations based on energy flow could create the potential for overlaps/duplications of billing units.

  Action Item – SPP staff to confirm the following –
    - How many of the TCRs represent converted ARRs?
    - What is the basis of the ARR and TCR numbers (are both based on hourly/annual)?

Fee Structure Development

The remainder of the meeting was spent contemplating various alternatives to allocate the costs as reported in the three FERC categories -

- Scheduling, System Control & Dispatch
- Market Facilitation, Monitoring & Compliance
- Reliability Planning & Standards Development

There was a fair amount of time spent reviewing the components for each of the categories and discussing the methodologies utilized by other RTO/ISOs. Schedules/analysis from previous meetings served as the reference point for much of this discussion.

In contemplating potential structures, members voiced their concern about making this either overly complicated or too simplistic. An overly complicated methodology could result in incremental costs to implement and maintain. At the same time, a simplistic method might be difficult to justify in our FERC filing.

Rob Janssen shared information obtained from the NYISO outlining the process they went thru to restructure their rates, which included the engagement of an external consultant to perform an extensive review of their operating costs, which consisted mainly of assigning all costs as being attributable to load, supply, or non-physical transactions. There was general agreement that the structure ultimately proposed by the task force would have to be thoroughly supported by analysis when submitted to FERC for approval.

  Action Item – SPP staff to research the filings that other RTO/ISOs have made when proposing changes to their rate structure to understand the level of justification that is typically required in these matters.

There was discussion on what billing units would be utilized in the denominator for those costs that would potentially be allocated based on energy flow. There was general agreement about the inclusion of generation, load, import/exports, and pseudo ties. Concern about the potential for duplicating charges arose when other determinants were added to the conversation (TCRs, ARRs, virtuals).

Before the meeting closed there was an informal poll taken to assess the level of support for a methodology that would propose market costs be allocated based on energy flow and planning & scheduling costs be allocated based on demand. The results of the informal poll were 9-2-2 (yes-no-abstain).

> **Action Item** – SPP staff to prepare several different strawman scenarios representing alternative rate structures based on the FERC expense categories (market, planning, scheduling).

Future Meetings

Thursday, October 4th 10-Noon – Teleconference
Monday, October 15th 1PM -6PM (Face to Face) – Little Rock

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

Respectfully Submitted,

Dianne Branch
Secretary

Southwest Power Pool

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE
DFW Hyatt Regency – Dallas, TX
September 6, 2018

• ATTENDANCE LIST •

Name	System
Dianne Branch	SPP
Mike Riley	SPP
Jason Mazigian	Basin Electric
John Varnell	TENASKA
Ray Bergmeier	Sunflower
David Mindham	ITC
Robert Tollman	OG+E
CARL A. MONROE	SPP
John Olsen	Evergy
Rob Janssen	Dogwood Energy
Alfred Busbee	ETEC
Wes Berger	SPS/Xcel Energy
David Erkin	AEP
GREG GARST	OPPD
Joel Dagerman	NPPD

Dianne Branch

From: Jacoby, Jim
Sent: Wednesday, September 05, 2018 12:13 PM
To: Olsen, John; Dianne Branch
Cc: David Erkin
Subject: **External Email** Proxy

John, please give my proxy to David Erkin for this weeks meeting. Thanks

Jim Jacoby
AEP
214-777-1144 Office
214-773-3043 Cell
jwjacoby@aep.com

Sent from my iPad

Dianne Branch

From: Olsen, John
Sent: Thursday, September 06, 2018 9:55 AM
To: Dianne Branch
Subject: **External Email** Fwd: 1ATF Proxy - Tim Hall

FYI

John Olsen
KCP&L and Westar, Evergy Companies
Sr. Director, DSO and Emergency Ops
O: 816-654-1130 M: 785-220-8343
kcpl.com
westarenergy.com
evergyinc.com

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.

From: Hall, Tim A. (SPC)
Sent: Tuesday, September 4, 2018 11:04:59 AM
To: John Olsen
Cc: rob.janssen@kelsonenergy.com
Subject: 1ATF Proxy - Tim Hall

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

John – Rob Janssen will have my proxy at this week's 1ATF meeting until I am able to join by phone. I have an ERCOT meeting the same day in Austin.
Thanks,
Tim Hall
Southern Power
3535 Colonnade Parkway
Birmingham, AL 35243
BIN S-950-EC
Tel 205.992.0040
Mob 334.391.6206
Southern Power

Southwest Power Pool

Southwest Power Pool, Inc.

SCHEDULE 1A TASK FORCE MEETING

September 8, 2018

DFW Hyatt Regency

• A G E N D A •

10AM – 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. Requested Analysis from 8/24 Teleconference (60 minutes) ....Dianne Branch/Various
   a. Overview of 1A/Assessment Billing Process
   b. Criteria for 12CP/NCP
   c. Network and PTP – Three Year Analysis
   d. Generation Nameplate Capacity Analysis
   e. Market Transactions – Three Year Analysis
3. Fee Structure Development (180 minutes)…………………………………………………..John Olsen
4. Closing Items (10 minutes)…………………………………………… ……………………Dianne Branch
   a. Summary of Action Items
   b. Future meetings

Southwest Power Pool

SCHEDULE 1A TASK FORCE MEETING

August 24, 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
Alfred Busbee	GDS Associates/ETEC
Jason Mazigian	Basin Electric
David Mindham	ITC Holdings
Tim Hall	Southern Power
John Varnell	Tenaska
Robert Tallman	OG&E
Wes Berger	SPS/Xcel Energy
Jim Jacoby	AEP
Greg Garst	OPPD
Joel Dagerman	NPPD
Heather Starnes	Missouri Joint Municipal Elec Utility Commission
Ray Bergmeier	Sunflower Electric
Rob Janssen	Dogwood Energy
David Erkin	AEP
Calvin Daniels	WFEC
Kevin Galke	The Energy Authority for City Utilities of Springfield
Carl Monroe	SPP
Mike Riley	SPP
Scott Smith	SPP
Lee Elliott	SPP
Micha Bailey	SPP
Patti Kelly	SPP
Ty Mitchell	SPP
Zeynep Vural	SPP
Dianne Branch	SPP

Minutes from the August 8, 2018 meeting were reviewed. Heather Starnes motioned to approve the minutes. The motion was seconded by Jason Mazigian. The minutes were unanimously approved by voice vote.

Review of FERC Expense Classification

Dianne Branch provided an overview of SPP's methodology for categorizing the components of its Schedule 1-A administrative fee as required by FERC Order 668. Exhibits detailing the components of each prescribed category were also reviewed. There were various questions regarding the general process and specific components of the allocation that were addressed by SPP staff.

Review of TCR Estimated Cost of Services

Dianne Branch provided a brief overview of the estimated cost to provide the TCR services, highlighting the associated staffing, system maintenance, and debt service cost. Annual costs are estimated at $2.3MM.

Review of RTO Comparisons (Order 668 Fee Allocation)

Dianne Branch provided an overview of other RTO/ISO rate schedules and their allocation to the three expense categories as prescribed by FERC Order 668. There was a general discussion on the varying complexity of the different rate structures employed by the other RTO/ISOs and the related allocation to the FERC expense categories. The task force generally agreed that the methodology ultimately recommended for SPP should not be overly complicated and should minimize any incremental costs to implement and administer.

Fee Structure Development

There was ongoing discussion focused on the various approaches for constructing the cost recovery rate structure. While the general consensus is "simpler is better", there were differing positions on what level of simplicity would be most appropriate. Consistent with discussions from the August 8th meeting, there is general agreement that the current schedule 1A billing methodology should be utilized for costs associated with Scheduling and Planning. In summary, billing for those two areas would be based on demand to transmission customers.

The remainder of the discussion centered on the appropriate mechanism(s) to bill costs associated with Market Facilitation. Specifically, whether it should be based entirely on energy flow and to what level of granularity should market costs be evaluated and potentially allocated to those receiving benefit. Additional analysis was requested of staff to assist the task force in further evaluating market services for purposes of constructing an appropriate rate recovery structure.

There was general agreement that a pre-filing conference with FERC should be considered within the scope of the overall project timeline.

Action Items

Staff to provide clarification on the difference between SPP 12NCP and 12CP.

Staff to accumulate data on nameplate capacity of all generation assets

Staff to provide additional volume data for various market services, with special emphasis on TCR activity

Staff to formulate approach in seeking a pre-filing conference with FERC

Costs of implementing /administering new rate structure to be evaluated and included in the final recommendation

True-up mechanism to be formulated once new rate structure has been solidified

Future Meetings

Thursday, September 6th 10AM -3PM (Face to Face) – DFW Hyatt Regency
Thursday, October 4th 10-Noon – Teleconference

There being no further business, John Olsen adjourned the meeting at 12:10 PM.

Respectfully Submitted,

Dianne Branch
Secretary

Schedule 1A Current Billing Process Overview

1A Task Force

September 6, 2018

Schedule 1A Calculation

Consists of 3 Separate Components -

- Network Integrated Transmission Service (NITS) – Settled per Operating Month
- Point to Point (PTP) – settled per Operating Day
- Monthly Assessment – acts as a true up to cover any unreported load not covered by PTP or NITS

Schedule 1A Calculation

Consists of a Three Step Process –

- 1 - NITS Calculation
  - 1A Rate x Schedule 9 PYCP average x Number of hours in the month
- 2 - PTP Calculation
  - 1A Rate x Total Reserved Capacity (per TSR)
- 3 - Monthly Assessment Calculation
  - 1A Rate x All Reported Load minus amounts billed in Step 1 and Step 2

Monthly Assessment will either be a charge or zero.

If calculation results in a credit, it is adjusted back to zero.

Network and PTP - 3 Year Analysis

1A Task Force

September 6, 2018

Schedule 1A Revenues (2015-17)
(in 0,000s)

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

Note: There was an adjustment in 2016 to reverse activity for changes in billing methodology that was implemented prior to obtaining FERC approval to change such methodology. This change related to eliminating the "credit" scenario for monthly assessments. The adjustment created a negative balance for revenues billed in 2016.

SPP

Schedule 1A – PTP Activity (2015-2017) (in $0,000s)

Revenue Breakdown			
Total Schedule 1-A Revenue	$ 451,847		
Total Point to Point (PTP)	36,910		
% of PTP to Total Schedule 1-A	8%		
PTP Customer Breakdown		**% of PTP**	**% of 1-A**
PTP only Customers	$ 22,803	62%	5%
Remaining PTP Customers	14,107	38%	3%
TOTAL PTP	$ 36,910		

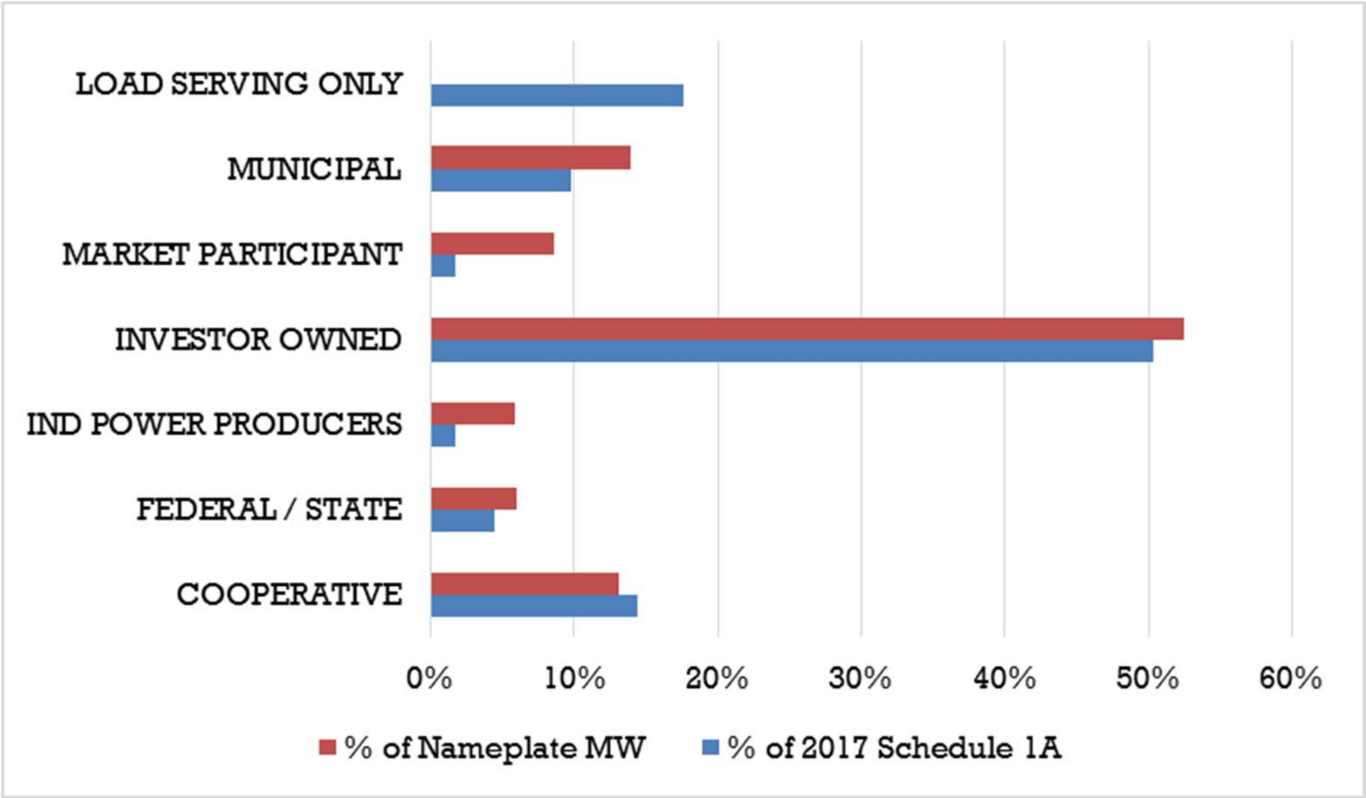
SPP

Generation Capacity Analysis

1A Task Force

September 6, 2018

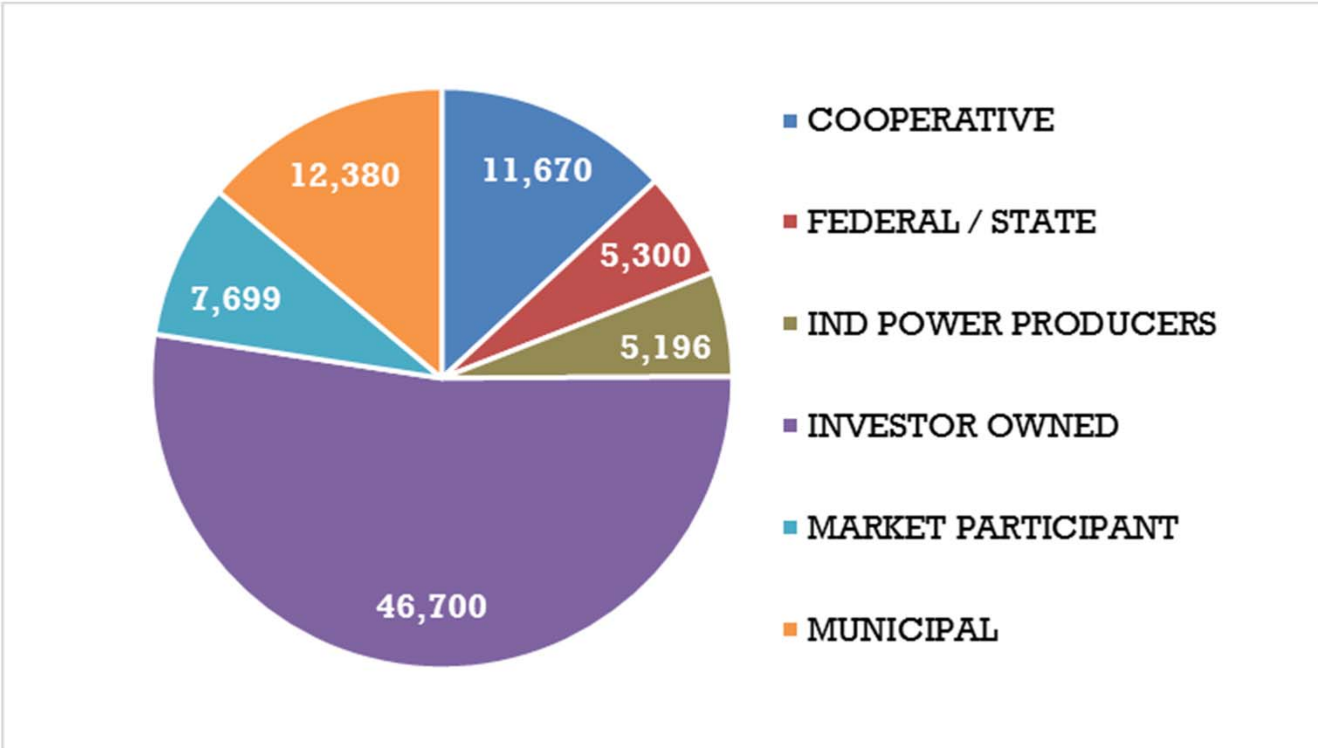
Schedule 1A & Generation Capacity



- Nameplate data from Commercial Model
- Market Participant group includes power marketers and wind farms not owned/registered by IOUs
- MPs & IPPs may have PTP reservations resulting in Sched 1A fees
- Muni/Fed/State/Coop: 33% of Nameplate & 29% of Sched 1A

SPP

Nameplate MW by Generation Group



Market Activity 2015-2017

1A Task Force

September 6, 2018

Billable Units (MWhs) by Market Service

	MWhs (in millions)			
Service Category	2015	2016	2017	MWh Based on
Real Time Generation	237	261	260	Total for all submitted generation meter MWh data for RT Markets.
Real Time Load	232	252	250	Total for all submitted load meter MWh data for RT Markets.
Transmission Congestion Rights	458	453	547	Total for all TCR instruments MWhs held by an Asset Owner.
Auction Revenue Rights	18	16	14	Total for all ARR instruments MWhs held by Asset Owner
Real Time Imports/Exports Only	16	17	18	Total for all Cleared Import/Export Tags MWhs for RT Markets
Virtual Energy Speculation	17	24	35	Total for all Cleared Virtual Offer/Bids MWhs for DA Markets
Bilateral Settlement Schedule Transactions	68	99	101	Total MWhs for all DA and RT Bilateral Settlement Schedules for the Seller and
Operating Reserves (Reg up, down, spinning and supplemental)	18	19	19	Total MWhs of Cleared activity in RT Markets
Pseudo-Tie	4	6	6	Total MWhs for a Pseudo-tied Out Load or Generation within the RT Markets
Total MWh Billable Units	1,068	1,146	1,250	