Memorandum

To: Finance Committee

From: SPP Staff

Date: April 5, 2011

Re: SPP Rate Structure

SPP's administrative costs are recoverable through assessments of Members and charges under Schedule 1A of the SPP Open Access Transmission Tariff (Tariff), which charges customers for transmission service received from facilities that are under the Tariff. Schedule 1A is billed to all transmission customers based on the type of service purchased:

1. Network transmission service is charged based on the 12-month average of the customer's coincident zonal demands, multiplied by the number of all hours of the applicable month.

2. Point-to-Point transmission service is charged for all reserved transmission capacity.

SPP implemented its Energy Imbalance Services Market (EIS Market) in early 2007, which allowed participants to acquire or sell at a market-based rate the energy used to balance schedules. Participants can transact in the EIS Market without paying a separate fee associated with the market service.

SPP expects to implement its Integrated Marketplace ("Marketplace") on March 1, 2014. The Marketplace will allow participants to hedge energy price risk a day in advance of delivery, acquire energy in real-time at market rates, protect against costs associated with transmission congestion, and acquire operating reserves to support their service requirements.

SPP functions as a consensus-oriented, member-driven organization. SPP's rate structure has been designed to support that focus. SPP has avoided implementation of activity-based rate structures and unbundled rate structures as they can undermine the consensus and regional focus which has been a hallmark of SPP through the years. An excellent example of this was when SPP subjected itself to SAS70 audits. Though the audits were designed to meet the regulatory needs of SPP's SEC jurisdictional members, the benefits of undergoing the audits benefited the entire SPP membership. As a result, the costs of the audits have been funded by SPP's Administrative Fee collected from the customers and members of the entire region instead of just from the SEC jurisdictional members.

While the rate structure currently in place has benefitted SPP, many factors are changing which call for a review of SPP's rate structure. Most significantly, with the implementation of the Marketplace in 2014, the scope of services provided by SPP will increase. These services are expected to result in new entities becoming active in SPP and their activities are not necessarily focused on SPP's core priority of keeping the lights on (Reliability). Additionally, SPP may see changes to its membership whereby load-serving utilities desire to be members but do not desire to have their transmission assets managed under the SPP Tariff. Although participation in SPP by these entities may serve SPP's ultimate reliability mission, it must be determined whether SPP's existing rate structure appropriately allocates the costs of SPP's services or if another rate structure better meets the needs of the SPP region.

SPP's Finance Committee and Board of Directors reaffirmed the load-based fee structure in 2007 because the EIS Market service was beneficial to all load in the region. With the expected advent of the Marketplace and the issues discussed above, it is appropriate for the Finance Committee and the Board of Directors to again review the rate structure. SPP staff provides the following background information to assist the Members, Finance Committee and Board of Directors in deliberations on this topic:

Funding Today

SPP has several funding mechanisms today. Capital expenditures are funded via term borrowings from banks and institutional investors. SPP's operating expenditure funding is more complex because there are a number of funding sources:

1. **North American Electric Reliability Corporation (NERC)** – SPP has a Delegation Agreement with NERC under which SPP receives funding from NERC for SPP's provision of Regional Entity services. The funding received is based on the Regional Entity's annual budget, which is prepared by SPP and approved by NERC.

2. **Schedule 12** – Each month SPP charges Tariff customers under Schedule 12 of the Tariff, which funds SPP's obligations to the Federal Energy Regulatory Commission (FERC). Schedule 12 rates are based on expected assessments from FERC, plus or minus under/over recoveries from prior years.

3. **Contract Services** – SPP provides services to several entities under fixed price contracts.

4. **Miscellaneous Income** – Primarily consists of compensation SPP receives for its generation interconnection engineering studies.

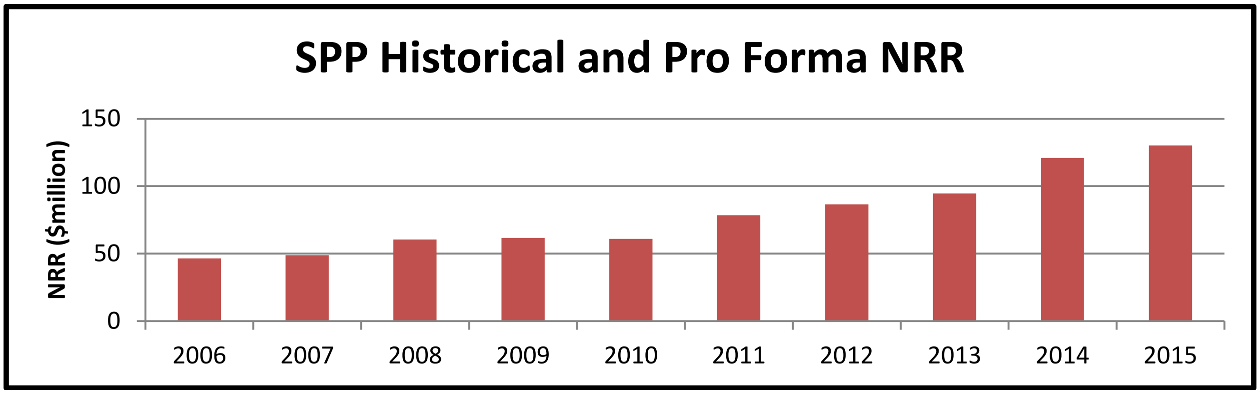
5. **Tariff Fees & Assessments** – Each month SPP assesses its load-serving members whose load can be served by transmission assets under the SPP Tariff based on their 12-month average coincident zonal demands, multiplied by the number of all hours of the applicable month, multiplied by the assessment rate established annually by the SPP Board of Directors. Since 2004, this rate has been equivalent to the rate charged under Schedule 1A of the Tariff.

   Load-serving members receive a credit against their monthly assessment for charges paid under Schedule 1A. In addition to the monthly assessment, this revenue category contains all Schedule 1A charges not credited against member's monthly assessments.

   SPP also collects a $6,000 annual membership fee from each member.

Historic and Future Costs (funded from Tariff Fees & Assessments)

As SPP's operations have matured and expanded, its costs, which are funded from Tariff Fees & Assessments revenue, have gradually increased. Design, development and implementation of the EIS Market was the significant contributor to expenditure growth into 2008. Since then, expenditure growth has been driven by expanded transmission planning services, compliance focus, and the design and development of the Marketplace.



Alternative Rate Structures

SPP's current rate structure allocates its net cost to customers and members based on transmission usage by load. The rationale behind this structure is that load is ultimately charged for all recoverable costs. Despite the theory that load is ultimately charged, other regional organizations have developed rate structures which recover the regional organization's costs from each market participant based on determinants other than load. The following data, prepared by Accenture, summarizes rate structures of three other ISOs/RTOs in the United States.

ISO-New England

Schedule	Name	Description	Who Pays
Schedule 1	Scheduling, System Control, and Dispatch	Service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area.	• Regional Network Service Customers • Transmission Customer receiving Through or Out Service
Schedule 2	Energy Administration Service	Service provided by ISO to administer the Energy Market.	Market Participants
Schedule 3	Reliability Administration Service	Service provided to administer Reliability Markets and associated transactions along with providing other reliability and information services.	Market and Non-market participants
Schedule 5	Collection of New England States' Committee on Electricity (NESCOE) Budget	Assessed to each customer that is obligated to pay the Regional Network Service Rate	• Generators • Transmission owners • Suppliers • Municipal utilities • Alternative resources • End-user customers

Midwest ISO

Schedule	Name	Description	Who Pays
Schedule 1	Scheduling, System Control, and Dispatch	Service required to schedule the movement of power through, out of, within or into the Midwest ISO Balancing Authority.	Transmission Customers
Schedule 10	FERC Annual Charges Recovery	This fee represents the total amount of FERC Annual Charge collected from the Transmission Customers by the Transmission Provider	Transmission Customers
Schedule 10	ISO Recover Adder	Recovery of costs associated with building and operating the Security Center, including capital costs and operating expenses; and costs associated with administering the Tariff.	Transmission Customers Transmission Owners
Schedule 16	Financial Transmission Rights Administrative Service Cost Recover Adder	Service provided by the Transmission Provider to all MPs that are primary holders of FTRs through allocation, assignments, or auction.	FTR Holders
Schedule 17	Energy and Operating Reserve Markets Support Administrative Cost Recovery Adder	Service provided by the Transmission Provider to all MPs that participate in Transactions using the Transmission System or Energy and Operating Reserve Markets	Market Participants
Schedule 31	Reliability Coordinator Cost Recover Adder	Transmission Provider will recover its costs to provide Reliability Coordination Service pursuant to the terms of this Schedule 31 from Reliability Coordination Customers	Reliability Coordination Customers

PJM Interconnection

Schedule	Name	Description	Who Pays
Schedule 9-1	Control Area Administration Service	Comprises all the activities of PJM associated with preserving the reliability of the PJM region and administering Point-to –Point Transmission Service and Network Integration Transmission Service	Users of the Control Area Administrative Service
Schedule 9-2	Financial Transmission Rights Administration Service	Includes all activities of PJM associated with administering FTRs	FTR Holders
Schedule 9-3	Market Support Service	Comprises all the activities of PJM associated with supporting the operation of the PJM Interchange Energy Market and related functions	•Point-to-Point Customers •Network Integration Transmission Service to Generation Providers, •Entities that submit offers to sell or bids to buy energy in the PJM Interchange Energy Market.
Schedule 9-4	Regulation and Frequency Response Administrative Service	Ensures continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at 60Hz.	•Load Serving Entities •Generators

Schedule 9 - 5	Capacity Resource and Obligation Management Service	Comprises the activities of PJM associated with (a) assuring that customers have arranged for sufficient generating capacity (b) processing Network Integration Transmission Service; (c) administering the Reliability Pricing Model auctions for the PJM Region; and (d) administering or providing technical support for the RAA	• Load-Serving Entities • Owners of Capacity Resources.
Schedule 9 - 6	Formula Rate for Costs of Advanced Second Control Center	Recovery of the costs of the planned advanced second control center (AC2)	• Users of PJM System
Schedule 9	Organization of PJM States, Inc. ("OPSI")	Recovers PJM's payments to OPSI .	• Point – to Point Customers • Network Integration Transmission Service Customers
Schedule 9	FINCON – Finance Committee Retained Outside Consultant	Assessed based on the engagement of one or more consultants to the Finance Committee.	
Schedule 9	MMU Funding	Recovers the costs of providing the market monitoring functions to the PJM region.	• Point – to Point Customers • Network Integration Transmission Service Customers • Generation Providers • Entities that submit offers/bids

Lessons From Other Regions

Discussions with ISO-NE and PJM regarding their rate structures yielded a few central themes and guiding thoughts:

- Load serving entities generally pay 70%+ of ISO-NE and PJM's administrative costs. SPP estimated its load-serving entities would pay 93% of SPP's administrative costs in an unbundled rate environment, which appears consistent with the predominantly integrated structure of utilities within the SPP region.

- In ISO-NE and PJM, rates are charged at a stated rate then "trued-up" after the fact (either quarterly or annually). This structure ensures known rates for market participants, generally provides appropriate cash flow for RTO operations, and limits the volume of regulatory interactions once the structure is approved.

- The administrative burden of performing actual billing under an unbundled rate structure is relatively insignificant; however, it takes meaningful effort from staff and stakeholders to create an unbundled rate structure. Depending on the style of the structure, additional recurring regulatory work could be expected.

- Rate designs should be as simple as possible and utilize billing determinants the regional organization already uses and tracks.

- One regional organization indicated that a significant aspect of its rate design was enforcing a modest charge to enter bids. This charge helps control the volume of bids the regional organization needs to process, and ensures participants have some financial stake in their bids and offers.

Simple Comparison – SPP's 2010 Actual vs. Alternative Rate Structure

The following simple example compares SPP's 2010 Tariff Fee and Assessment collections by entity, using an Alternative rate structure which recovers "market" costs[1]. SPP charged a Tariff Fee and Assessment rate of 19.5¢/MWh during 2010 resulting in collections of approximately $65 million. In compliance with FERC Order 668, SPP reports its Tariff Fee and Assessment rate allocated across three services, as follows:

	2010 Rate	2010 Collections
561.4 Scheduling (49%)	9.59 cents per MWh	$32 million
561.8 Reliability Services (9%)	1.68 cents per MWh	$ 5 million
575.7 Market Services (42%)	8.23 cents per MWh	$28 million

The Alternative rate structure for our example would recover costs for Scheduling and Reliability from all load just as it is done today in SPP. Costs for Market services would be recovered from all participants in SPP's EIS market based on the volume of energy transacted in the market. Therefore, SPP would collect $32 million from the load for Scheduling services and $5 million from load for Reliability services in the same ratios as done today (no cost shift for these services). Market service costs of $28 million would be recovered from the entities responsible for the 12.3 million MWh of energy transacted during 2010 in the EIS market on a pro rata basis ($2.28/MWh of energy transacted). The following table highlights entities whose total fee paid to SPP would change by at least $0.5 million under this Alternative rate structure for 2010.

Entities With Increased Costs		Entities With Decreased Costs	
Name	$ Change	Name	$ Change
NPPD	$ 549	WESTAR	$ (1,982)
WFEC	$ 618	OGE	$ (1,099)
SUNFLOWER	$ 786	UTILICORP	$ (1,019)
KCPL & GMOC	$ 799	SPS	$ (689)
NOBLE GREAT PLAINS WIND	$ 844		
GSEC	$ 1,046		
OPPD	$ 2,503		

The Alternative rate structure example illustrates the impact of shifting costs to participants in the EIS market rather than allocating across all loads in the SPP region. For illustration, OPPD represented approximately 5% of transmission service sold by SPP during 2010 and thus paid approximately 5% of SPP's administrative costs during the year. However, OPPD represented 14% of all transactions settled by SPP's EIS market in 2010 which, under the Alternative rate structure, would have resulted in OPPD paying $2.5 million more of SPP's administrative costs since OPPD's participation in the SPP EIS market exceeded its load ratio share of the SPP footprint. Conversely, Westar represented nearly 11% of SPP's transmission service sales but only 3.5% of its EIS market sales; therefore, under the Alternative rate structure, Westar would be responsible for a smaller portion of SPP's administrative costs.

Extending this example to 2015 (the first full year of Marketplace operations) illustrates even greater shifting of costs among customers and members. In 2010, 42% of SPP's net revenue requirement was allocated to "market" costs. A very rough estimate indicates "market" costs

[1] In compliance with FERC Order 668, SPP reported its administrative fee costs allocated across three functional services. Based on this allocation, SPP collected $27.6 million for "market" services during 2010. In the example above, SPP uses this amount as a proxy for recoverable "market" costs that would be collected in the alternative rate structure.

may comprise 56%[2] of SPP's 2015 net revenue requirement.

If 2015 Integrated Marketplace participation follows 2010 EIS Market activity, there would be a significant shift in costs towards active market participants. This assumption illustrates the shift in costs from a fully load ratio share to "market" costs being fully recovered from market participants based on their potential use of services. The example is not intended to be an exact representation of how SPP believes the Marketplace activity will be, merely representation of a possible outcome.

Top 10 Admin Fee Current Method			Top 10 Admin Fee Alternative Method		
	2015 Spend			2015 Spend	
AEP	$	20,027	AEP	$	20,377
OGE	$	16,461	OGE	$	13,534
SPS	$	14,328	OPPD	$	13,360
WESTAR	$	14,046	KCPL & GMOC	$	12,520
KCPL & GMOC	$	10,392	SPS	$	12,492
OPPD	$	6,694	WESTAR	$	8,766
NPPD	$	6,634	NPPD	$	8,097
UTILICORP	$	4,844	WFEC	$	5,799
WFEC	$	4,151	GSEC	$	3,799
EMPIRE	$	3,106	SUNFLOWER	$	3,251

Clearly this is a very simplistic example based on historical data and doesn't account for the breadth of transactions which may occur in the Marketplace. Additionally, this example does not account for potential changes in customers' behavior if an alternative rate structure had been in place during 2010.

Other Considerations

SPP Bylaws
SPP's Bylaws prescribe its assessment policy and process; specifically, that SPP will assess certain members all costs not otherwise collected. Changes to the Bylaws, if necessary, would need further approval from SPP's lenders.

Annual Membership Fee
SPP currently charges each member an annual $6,000 membership fee. Certain members whose load is served by transmission assets not under the SPP Tariff can use some SPP services for only the cost of the annual membership fee. These services, such as regional reliability coordination, have values we believe are well in excess of the annual membership fee.

Benefits
As a corporation, SPP would realize little direct benefit from changing its rate structure. Under the current methodology or any potential alternative methodologies, SPP's rates would be designed to fully cover the cost of its operations. Customers and Members, depending on how they use SPP's services, would see shifts in their portion of SPP's administration fees under different rate structures. If SPP advocates a change in its rate structure, consideration must be given to whether or not an unbundled rate structure would more appropriately allocate SPP's administrative costs

[2] Assumes 62 staff additions at annual burden of $120,000, principal and interest associated with known financing, 2010 "market" allocation growing at 5% per year, and additional $20 million in annual overhead allocation (totals $73.6 million versus net revenue requirement of $131.2 million).

ISO/RTO Voting Structures & Affiliate Voting

Corporate Governance Committee

November 28, 2017

Voting Structures

CAISO	Board of Governors members are appointed by the Governor of California (and confirmed by the California senate) (CAISO Bylaws § 4.1); the Board may establish committees including both Board and non-Board members, voting in such committees does not appear to be specified
ERCOT	Organized into voting (corporate) and non-voting (associate and adjunct) membership classes by sector;[1] "Affiliated Entities" may hold only one Corporate Membership
ISO-NE	Stakeholders organized by sector into the New England Power Pool (NEPOOL) with advisory votes; membership classes include End Users, Alternative Resources Providers, Data-Only Participants, and Provisional Members (Second Restated NEPOOL Agreement§ 3.1(c))
MISO	MISO Board of Directors members are elected by MISO Members (which include transmission owners and "Eligible Customers" who pay the membership fee) (MISO Transmission Owners Agreement, Art. Two, § III.A.1); Stakeholders are organized by sector[2] with representation on the Advisory Committee to the MISO Board of Directors, which uses weighted sector voting For non-Advisory Committee groups, voting is limited to one vote per Voting Member, and parent companies are considered to be the "Voting Member" for all affiliates, even if those affiliates separately register as MISO members (MISO Governance Guide § 7.3.1)
NYISO	New (non-initial) NYISO Board of Directors members are elected by existing Board members (NYISO Bylaws Art. II § 3, Art. III § 3(b); NYISO Agreement § 5.04) Stakeholders share governance on a voting basis with the NYISO Board of Directors via three standing committees -- the Management Committee,[3] Operating Committee,[4] and Business Issues Committee[5] -- comprised of major market sector representation[6]
PJM	PJM Board of Managers members are elected by Voting Members,[7] with affiliated companies having a single vote (PJM Operating Agreement §§ 7.1, 8.1.1, 1)

[1] Consumer (residential, small commercial, large commercial, industrial), cooperative, independent generator, independent power marketer, independent retail electric provider, investor-owned utility, and municipal.

[2] Independent power producers and exempt wholesale generators; transmission owners; municipals, cooperatives, and transmission dependent utilities; power marketers; public consumer advocates; state regulatory authorities; environmental/other stakeholder groups; eligible end-use customers; coordinating members; and transmission developers.

[3] Comprised of each party to the ISO Agreement, each of which belongs to one of the five sector groups

[4] Created per the ISO Agreement to coordinate operations, develop procedures, evaluate proposed system expansions and act as a liaison to the New York State Reliability Council (NYSRC)

[5] Created per the ISO Agreement to establish rules related to business issues and provide a forum for discussion of such rules and issues

[6] End-use consumers, generation owners, other suppliers, public power and environmental interests, and transmission owners

[7] Section 1 of the PJM Operating Agreement defines the term "Voting Member" as, "(i) a Member as to which no other Member is an Affiliate or Related Party, or (ii) a Member together with any other Members as to which it is an Affiliate or Related Party."

Affiliate Voting

A survey was distributed among the ISO/RTO corporate secretary group as to how others are addressing affiliates in their governing documents. To date, ISO-NE has responded.

CAISO	Affiliate information does not appear to be used for voting purposes
ERCOT	Article 2 of the ERCOT Bylaws define the term “Affiliate” as including an entity (e.g. a person or any type of organization) in any of the following relationships: (i) an entity that directly or indirectly owns or holds at least five percent of the voting securities of another entity, (ii) an entity in a chain of successive ownership of at least five percent of the voting securities of another entity, (iii) an entity which shares a common parent with or is under common influence or control with another entity or (iv) an entity that actually exercises substantial influence or control over the policies and actions of another entity. Evidence of influence or control shall include the possession, directly or indirectly, of the power to direct or cause the direction of the management and/or policies and procedures of another, whether that power is established through ownership or voting of at least five percent of the voting securities or by any other direct or indirect means. In the case of (i) or (ii) above, where one entity owns or holds at least five percent, but less than 20 percent, of the voting securities of another entity, and the relationships in (iii) and (iv) do not exist, the Board shall have the discretion to determine whether or not the entities are Affiliates of one another for the purpose of determining Member Segment and voting rights. Similarly, in cases where the level of control or influence is disputed, the Board shall have discretion to determine whether or not the entities are Affiliates of one another. Membership in ERCOT shall not create an affiliation with ERCOT. Members **are** required to identify affiliates (at least upon application for membership) Affiliate relationships impact both member segment and voting rights, as an “Entity” is defined as including “an organization and all of its Affiliates.” (ERCOT Bylaws Art. 2 § 8)
ISO-NE	Affiliate information is not used for voting purposes, but, rather, for Code of Conduct purposes and for ISO-NE’s Market Monitor to make market power assessments Participants **are** required by tariff to identify affiliates
MISO	Members that are affiliates of a common parent are allowed a single vote; the parent company is considered to be the Voting Member (except as may be specified in a committee, subcommittee, working group, or task force charter and approved by the Steering Committee, which assists in coordinating the work of entities)
NYISO	For Management Committee purposes, a Member and any Affiliate or Affiliates are only allowed a single vote in a single sector; the Chairpersons and Vice-Chairpersons of the Management Committee, Operating Committee, and Business Issues Committee are to be from different sectors and may not represent the same Member or its Affiliates
PJM	For purposes of senior standing committees, all affiliated companies have one vote (PJM Operating Agreement §§ 1, 8.1.1)