Southwest Power Pool

REGIONAL STATE COMMITTEE

Austin, Texas

July 27, 2005

• M I N U T E S •

Administrative Items:

Members in attendance or represented by proxy were:

Denise Bode, Oklahoma Corporation Commission (OCC)
Sandra Hochstetter, Arkansas Public Service Commission (APSC)
Brian Moline, Kansas Corporation Commission (KCC)
Julie Parsley, Texas Public Utility Commission (TPUC)
Steve Gaw, Missouri Public Service Commission (MPSC)
David King, New Mexico Public Regulation Commission (NMPRC)

Others in attendance:

Ben R. Lujan, Chairman, New Mexico Public Regulation Commission
Richard House, Arkansas Public Service Commission
Larry Holloway, Kansas Corporation Commission
Tom DeBaun, Kansas Corporation Commission
Mike Peters, Kansas Corporation Commission
Mike Proctor, Missouri Public Service Commission
Ryan Kind, Missouri Office of the Public Counsel
Joyce Davidson, Oklahoma Corporation Commission
Adrianne Brandt, Texas Public Utility Commission
Bridget Headrick, Texas Public Utility Commission
Jim Eckelberger, SPP Director
Nick Brown, SPP
Les Dillahunty, SPP
Stacy Duckett, SPP
John Mills, SPP
Cheryl Robertson, SPP
Tony Ingram, Federal Energy Regulatory Commission
Dennis Reed, Westar
Don Taylor, Westar
Bary Warren, Empire District
Steve Owens, Entergy
John Gunesch, OG+E
Bill Wylie, OG+E
David Kays, OG+E
Mel Perkins, OG+E
Walter Wolf, Stone, Pigman, Walther, Wittman, LLC
Collin Wolf, Boston Pacific
Tom Littleton, OMPA
Michael Desselle, AEP

Richard Ross, AEP
Robert Pennybaker, AEP
Robert Tumilty, AEP
David Brian, East Texas Cooperatives
Tracey Hannon, Southwestern Power Administration
Raksha Krishna, EEI
Walt Shumate, EEI
Kurtz Stowers, Calpine

President Bode called the meeting to order at 1:00 PM CDT. Secretary Parsley called roll and a quorum was declared. President Bode asked for adoption of the June 22, 2005 meeting minutes**. Secretary Parsley moved to adopt the June 22, 2005 minutes. Vice President Hochstetter seconded the motion. Hearing no objection, the minutes were adopted.** President Bode then asked for adoption of the July 11, 2005 teleconference minutes. **Secretary Parsley moved to adopt the July 11, 2005 minutes. Vice President Hochstetter seconded the motion. Hearing no objection, the minutes were adopted.**

Updates:
Les Dillahunty provided a financial report (RSC Financial Report – Attachment 1). Mr. Dillahunty reviewed the RSC budget performance and asked for any questions.

Vice President Hochstetter reported that an independent CPA firm had performed a 2004 RSC audit of SPP's records. The results were good and showed good accounting processes. **Secretary Parsley moved to approve the 2004 RSC audit. Vice President Hochstetter seconded the motion. Hearing no objection, the audit was approved**.

Tony Ingram reported that Commissioner Joseph Kelliher has taken over the duties of Chairman of the Federal Energy Regulatory Commission. Mr. Ingram stated that the Commission terminated the Single Market Design rulemaking. Future FERC meetings will be the third Thursday of every month.

Mr. Nick Brown provided an update of Southwest Power Pool (SPP) activities. The SPP Board of Directors met in Tulsa July 26 and addressed the following items:

- A Strategic Plan for 2005 was approved unanimously for a 1-3 year period.
- The SPP Board of Directors approved the Markets and Operations Policy Committee's (MOPC) recommendation to extend the EIS Market implementation to May 1, 2006.
- The SPP officers were granted the authority to execute an agreement pursuant to a 205 filing to form an Entergy ICT. The agreement is not signed to date pending Entergy's state authorizations.
- In the past, there has not been a transmission definition on a regional basis and there is a need for consistency. The biggest controversy is that of inclusion of radial lines.

Regarding the transmission definition, the MOPC recommended that the transmission definition should be: All non-radial power lines, substations, and associated facilities, operated at 60 kV or above, plus all radial lines and associated facilities operated at or above 60 kV that serve two or more eligible customers not affiliates of each other. A second definition was suggested and amended to read: All non-radial power lines, substations, and associated facilities, operated at 60 kV or above, plus all radial lines and associated facilities operated at or above 60 kV. After considerable debate and straw votes from the Members Committee, the SPP Board of Directors passed the following transmission definition: All existing non-radial power lines, substations, and associated facilities, operated at 60 kV or above, plus all radial lines and associated facilities operated at or above 60 kV that serve two or more eligible customers not affiliates of each other. All facilities operated at 60 kV and above constructed in the future would be included.

Mr. Brown asked for comments from the RSC who earlier declared support for the definition recommend by the MOPC. Following discussion, it was requested by President Bode that cost impact of the new definition be put in writing and tested in the Oklahoma companies. Vice President Hochstetter requested that in going forward if the RSC was to be useful there should be time to evaluate critical decisions to allow the RSC to take a position.

Business Meeting:
President Bode called on Mike Proctor for a report from the Large Generation Interconnection Task Force (LGIA Task Force Report – Attachment 2). Dr. Proctor reviewed the LGIA Task Forces' work to date. The task force has proposed the region-wide postage stamp rate option as the best alternative for cost allocation. Dr. Proctor pointed out the pros and cons of the postage stamp proposal. Commissioner Steve Gaw suggested that the Cost Allocation Working Group (CAWG) work with the LGIA Task Force to finalize this proposal and come back to the RSC.

Mr. Les Dillahunty provided information regarding the assessment of impact upon the Cost Benefit Study if a different natural gas forecast was utilized (Cost Benefit Study Report – Attachment 3). Mr. Ralph Luciani (Charles Rivers Associates) reported that to run a new study would cost approximately $50,000 and take several weeks to perform. The RSC made no specific suggestion on any follow-up action concerning the CRA analysis encouraging SPP to "do the right thing." Mr. Dillahunty also reported that in the course of performing a follow-up allocation analysis for Aquila on the Aquila sensitivity cases, CRA discovered that the ownership shares for some jointly owned generating units in SPP had been incorrectly input into the allocation model. The impact of the corrected data is included in the attached report. These corrections will be filed with the appropriate state jurisdictions and made available to all stakeholders.

In the matter of SPP data confidentiality, it was decided that this would be handled by teleconference in the near future at a date to be announced.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President Bode noted that the next regular scheduled RSC meeting is in Santa Fe, New Mexico on October 24. The SPP Board of Directors will be meeting on October 25, also in Santa Fe.

With no further business, the meeting was adjourned.

Respectfully submitted,

____
Julie Parsley, Secretary

Regional State Committee
Budget Performance
June 2005

	Jun 05	Budget	$ Over Budget	Jan - Jun 05	YTD Budget	$ Over Budget	Annual Budget
Income							
4900 · Other Income	459.34	13,655.00	(13,195.66) **(A)**	786,076.00	116,975.00	669,101.00 **(D)**	1,422,665.00
Total Income	459.34	13,655.00	(13,195.66)	786,076.00	116,975.00	669,101.00	1,422,665.00
Expense							
6000 · Operating Expenses							
6200 · Meeting-related Travel	459.34			25,861.67			
6300 · Administrative	0.00			2,281.60			
6000 · Operating Expenses - Other	0.00	13,655.00	(13,655.00) **(A)**	0.00	116,975.00	(116,975.00) **(B)**	222,665.00
Total 6000 · Operating Expenses	459.34	13,655.00	(13,195.66)	28,143.27	116,975.00	(88,831.73)	222,665.00
6800 · Outside Services							
6810 · Cost-Benefit Study							
6811 · Energy Imbalance	0.00	0.00	0.00	757,932.73	0.00	757,932.73 **(C)**	0.00
6812 · Ancilliary Services	0.00	0.00	0.00	0.00	0.00	0.00	400,000.00
6813 · Congestion Management	0.00	0.00	0.00	0.00	0.00	0.00	800,000.00
Total 6810 · Cost-Benefit Study	0.00	0.00	0.00	757,932.73	0.00	757,932.73	1,200,000.00
Total 6800 · Outside Services	0.00	0.00	0.00	757,932.73	0.00	757,932.73	1,200,000.00
Total Expense	459.34	13,655.00	(13,195.66)	786,076.00	116,975.00	669,101.00	1,422,665.00
Net Income	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

NOTE: Net Income for actual results and budgeted amounts will be $0 due to the fact that expenses incurred are reimbursed 100% by SPP. Reimbursements are recorded as income. Therefore, expenses will always equal income.

(A) Current month expenses relate entirely to travel related expenses for RTWG and MWG meetings and were less than what was assumed in the budget. Revenue relates to reimbursements from SPP for those expenses.

(B) Year to date expenses are less than budget due to meeting related expenses being less than what was assumed in the budget.

(C) Year to date costs for outside services have been greater than budget due to the fact that expenses for the cost benefit study relating to the energy imbalance market were budgeted in 2004 and actual costs were not incurred until 2005.

Regional State Committee
Budget Performance
June 2005

Jun 05	Budget	$ Over Budget	Jan - Jun 05	YTD Budget	$ Over Budget	Annual Budget

(D) Year to date revenue is greater than budget due to expenses to date being greater than what was assumed in the budget. See (B) and (C) for expense variance explanations.

RSC Regional State Committee
FOR THE SOUTHWEST POWER POOL

1000 Center St. Little Rock, AR 72201

LGIA Task Force Recommendation on the Allocation of Generation Interconnection Costs

Status Report to the SPP RSC

July 27, 2005

Austin, TX

Current SPP Tariff Provisions for Large Generation Interconnection Facilities

- FERC Order 2003 A, B, C
  - Requires the generator to **front the money** required to cover the cost of generation interconnections.
  - Policy requires the Transmission Owner to refund to the generator any money fronted for transmission **network upgrades** at the time that the generator begins injecting power into the grid.
  - Facilities that are **only used by the generator** are not considered to be a part of the transmission network and are not subject to the refund policy – the generator can “own” these facilities.

Example of Upgrades Required

- Suppose the following interconnection facilities and upgrades are required:
  1) Generator step-up transformer to get voltage to the transmission level.
  2) Radial line running from the generator step-up transformer to the transmission system.
  3) Substation (3-breaker ring bus) required to connect the power from the generator to the transmission system.
  4) Upgrades to the transmission system to deliver the additional power from the generator.

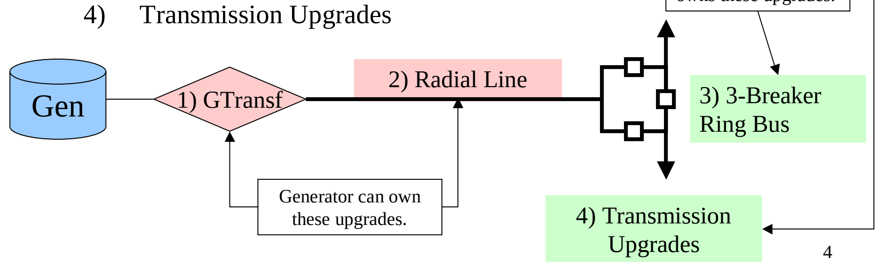
     These upgrades can vary depending on whether the generator wants to connect as:
     – Energy Resource - delivers to SPP market
     – Network Resource - delivers to specific load.

Facilities Included vs. Excluded from Refund Policy

Excluded from Refund – *Directly Assigned Facilities*
1) Generator step-up transformer (GTransf)
2) Radial Line to Transmission Network

Included for Refund – *Network Upgrade Facilities*
3) 3-Breaker Ring Bus (Substation)
4) Transmission Upgrades

Transmission Owner owns these upgrades.

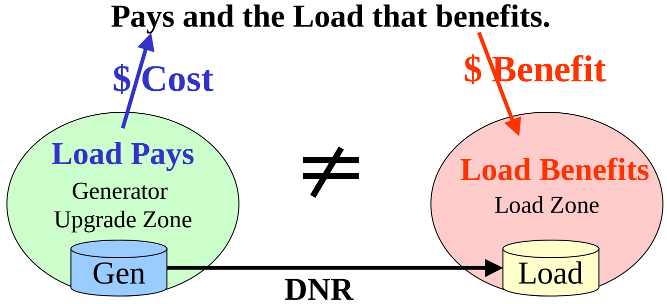


Under Current SPP Interconnection Tariff, WHO REFUNDS?

- The Transmission Owner who receives the up front money from the Generator is responsible to refund money received for network upgrades.
  - These payments are typically spread out over a multi-year time period (**cannot exceed 20 yrs**).
- In order to recover the costs, the Transmission Owner will include these costs to be recovered in its zonal rate.

BUT, This Can Be A Problem!

Mismatch Between the Load that Pays and the Load that benefits.



Currently is a ***Real Issue***!

- Midwest Energy
  - a small (cooperative) transmission owner in Kansas
  - whose transmission zone includes multiple sites for the location of wind power.
- Under the current SPP tariff,
  - Midwest Energy must provide the interconnections for developing wind power; (generator fronts the money)
  - Must refund costs for both substation and transmission upgrades within its zone.
- **But**, Midwest Energy's Load is not the beneficiary of the wind power being produced.

Three-Part Solution:

Energy Resource Interconnection Service (ERIS)

1. Limit the generation interconnection costs to "attachment facilities"
2. Address any capacity upgrades required for the capacity of generator to be put into the transmission system as either Requested upgrades or as a Transmission Service Request.
3. Allocate the cost of "attachment facilities" to a region-wide (postage stamp) charge.

Part 1: Limit ERIS to Attachment Facilities

- Energy Resource Interconnection Service (ERIS) allows the Interconnection Customer to attach to the Transmission System and use the <u>available</u> Firm and Non-Firm capacity of the *existing* Transmission System.
  – Attachment Facilities will typically only include 3-breaker ring bus (~ $2.5 M)
  – Attachment Facilities exclude any costs associated with upgrades to existing transmission capacity.

Part 2: Capacity upgrades can be requested either at the same time as ERIS, or after ERIS is requested.

- Transmission Request: There is a designated load
  – Network Service: New Designated Network Resource
    - Eligible for base funding (1/3 Postage Stamp and 2/3 Inc MW-mile)
  – PTP Service: From the Generator to the load
    - Load in SPP – eligible for base funding
    - Load outside SPP – eligible for Attachment Z credits
- Requested Upgrade: There is not a designated load.
  – Energy Resource requesting capacity upgrades
    - A form of an economic upgrade – participant funded
    - Funder is eligible for Attachment Z credits

Part 3: Allocate Costs to Region-Wide Postage Stamp Rate

- Transmission Owner is allocated revenues collected by SPP from the region-wide postage stamp rate.
- These revenues offset the Transmission Owner's revenue requirements associated with the attachment facilities.

Evaluation Summary

- Moving the cost allocation away from the zone in which the the generator attaches to the transmission system is a positive step in the right direction.
- Separation of attachment facilities from capacity upgrades to the transmission system is a positive step in the right direction.
- The implications for the cost allocation are as follows:
  - For new DNRs, this proposal moves the percent going to a region-wide rate from 33.3% to something in the range of 35.6% at the low end and 41.7% at the high end (see Appendix on Evaluation Details @ p. A-2). **This is not an insignificant change.**
  - For PTP service, the new revenues from that form of service will likely more than offset the costs – few "downsides" (see Appendix on Evaluation Details @ p. A-3).
  - Energy Only service is not a likely alternative – discount its importance for now (see Appendix on Evaluation Details @ p. A-4).

Discussion

- The proposal by the LGIA Task Force would increase the percentage of costs for new DNRs to be included in the postage stamp rate. **<u>Is this a problem?</u>**
  - If not, the LGIA Task Force will begin to develop tariff language to submit to the RTWG.
  - If so, the RSC can recommend that the CAWG work with the LGIA Task Force to further consider alternatives such as:
    - Roll attachment facilities costs into base funding
    - Use PTP revenues to pay back TO
    - Allocate cost to Designated Load

    The LGIA Task Force has evaluated other alternatives and can speak to why it selected the region-wide postage stamp rate option.

Appendix

Evaluation Details for the LGIA Task Force Proposal

New DNR Examples: Relative Size of Increase in Postage Stamp Component

1. Low End: Large Coal-Fired Plant @ 600 MW
   - Assume that the capacity upgrades are at the $180,000/MW limit.
   - ⇒ $108 M upgrade with $36 M going into the postage stamp rate.
   - This proposal would increase that amount to ~$38.5 M or 35.6% of the total cost (i.e., $38.5/$108 = 35.6%).
2. High End: Small Gas-Fired CT @ 50 MW
   - Assume that the capacity upgrades are below the limit at $60,000/MW.
   - ⇒ $30 M upgrade with $10 M going into the postage stamp rate.
   - This proposal would increase that amount to ~$12.5 M or 41.7% of the total cost (i.e., $12/$30 = 41.7%).

Overall Rate Impact from PTP Service

- Typical PTP Rate @ $1/kW/Month
  - 100 MW reservation ⇒ $100,000/Month and with 50% distributed back to all TOs as % Trans Rev Req ⇒ $50,000/Month or 12*$50,000 = $600,000 per year.
- Typical Cost for "Attachment Facilities"
  - $2.5 Million * 15% Fixed Charge rate = $375,000 per year.
- Since 50 MW is about the smallest size for a new generator,
  - 50% of PTP revenue distribution will likely cover more than the cost for attachment facilities.
  - Some difference between load ratio share and transmission revenue requirement share, but should be fairly similar.
  - Additional 50% distributed on MW-mile basis.
- Some "downside" features
  - Attachment Z will allocate some portion of the revenues to the PTP transmission customer for incremental service
  - Rate must cover the cost of new transmission capacity facilities.
  - Possible elimination of "out" rate by FERC per seams agreements with other RTOs.

Energy Only Resource

- Energy, <u>not</u> capacity benefits
  - An energy only resource must provide energy benefits to be economic. Otherwise, such a resource will not be funded.
  - The SPP region is fairly well saturated with new & more efficient gas-fired generation.
  - Difficult if not impossible to get the capital to fund a competitive coal-fired generator absent a capacity contract.
- Distribution of Energy Benefits
  - With zero congestion, the energy benefits will be SPP region wide.
  - With congestion, the energy benefits will be more localized to load that is upstream from the congestion.

Cheryl Robertson

Subject: Cost-Benefit Gas Price Sensitivity

-----Original Message-----
From: Les Dillahunty
Sent: Thursday, June 23, 2005 4:12 PM
To: 'Luciani, Ralph'; SPP Regional State Committee (EXPLODER)
Cc: Rudkevich, Alex; Wolfe, Ellen; Cuffman, Steve; Pat Bourne; Jeff Price
Subject: Cost-Benefit Gas Price Sensitivity

All,

During the RSC meeting on June 22 there was an agenda item and discussion concerning the CRA Cost/Benefit study, focused on insights gained by stakeholders after having had the opportunity to review the Study details. One of the specific questions of the RSC was an assessment of the impact upon the Study results if a different natural gas forecast were utilized. Ralph Luciani, CRA, who was in attendance agreed to provide an estimate of time and expense required to perform this alternative analysis.

Ralph has responded with the following alternatives. Option 1 references the data request submitted by the Arkansas Public Service Commission(APSC) regarding the recent filing of the Cost/Benefit study and supporting testimony in SPP's CCN application. The question posed by the APSC was:

1-8. How might you expect your core net benefit/(cost) findings to differ with high or low fuel price forecasts? Are your findings sensitive to fuel price forecasts?

I assume the RSC will consider the alternatives and provide the appropriate direction to SPP and CRA.

Les Dillahunty

-----Original Message-----
From: Luciani, Ralph [mailto:RLuciani@crai.com]
Sent: Thursday, June 23, 2005 10:23 AM
To: Les Dillahunty
Cc: Rudkevich, Alex; Wolfe, Ellen
Subject: Cost-Benefit Gas Price Sensitivity

Les, we talked over the higher natural gas price sensitivity that the RSC asked about and had a couple of ideas for your consideration:

1. Perform a side calculation in which natural gas prices are $2/mmBtu higher than those used in the study. (The 2006 gas prices used in the study are about $2/mmBtu lower than the current 2006 futures). Calculate the change in production cost savings (EIS vs. Base only), and use this change to infer the change in EIS market trade benefits to SPP (presumably positive). On the plus side, this could be done quickly with just a couple days effort from our staff, and perhaps could be used in response to the Arkansas data request 1-8 asking about this issue. On the negative side, it would not take into account the change in unit dispatch that would occur if higher gas prices were actually run through the MAPS model. This no-change-in-dispatch issue might be more of an issue when trying to allocate the trade benefits to individual companies (so perhaps we would not do that, instead noting in general terms that SPP trade benefits would increase by __%).

2. Re-run the MAPS Base and EIS cases with a higher gas price forecast (either $2/mmBtu higher, or using an updated forecast that we would have on

the shelf), and push the MAPS results through our SAS post-processing, individual company allocation, etc. This likely would take several weeks and roughly $50K to get right, given that 6 new MAPS runs would be required (2 cases x 3 MAPS years), and the significant amount of MAPS post-processing required. Working with the CBTF to discuss/decide on a specific alternative natural gas forecast and preparing a formal supplemental report discussing the results would add more time/budget.

Hope this helps. Let us know your thoughts.

Thanks,
Ralph

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SPP Cost-Benefit Study

- In the course of performing a follow-up allocation analysis for Aquila on the Aquila sensitivity cases, CRA discovered that the ownership shares for some jointly-owned generating units in SPP had been incorrectly input into the allocation model.
- Most were large coal-fired baseload plants that operate similarly in all scenarios and correcting the ownership shares would have only a minor impact on the individual company results.
- However, one of these jointly owners units, Stateline CC, is gas-fired and has a significant change in its dispatch between the Base and EIS cases.

SPP Cost Benefit Study

- Stateline CC had been treated as 100% owned by Empire. Correcting this to 60% Empire/40% Westar decreases the EIS market benefits for Empire and increases the EIS market benefits for Westar Energy from those originally presented in the Report.

EIS Market Case, Benefits (Costs) for Individual Transmission Owners Under the SPP Tariff
(in millions of 2006 present value dollars; positive numbers are benefits)

Original

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	70.0
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	5.3
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

Revised

Transmission Owner	Type	Benefit
AEP	IOU	58.5
Empire	IOU	47.9
KCPL	IOU	(2.2)
OGE	IOU	95.3
SPS	IOU	69.4
Westar Energy	IOU	27.4
Midwest Energy	Coop	(0.7)
Western Farmers	Coop	75.2
SWPA	Fed	1.2
GRDA	State	(5.0)
Springfield, MO	Muni	6.0
Total		373.1

SPP Cost Benefit Study

- In turn, this correction increases the EIS market benefits for Kansas, and decreases those for Missouri from those originally presented in the Report. There are also some minor changes to the benefits of other states where Empire is located.

EIS Market Case, Benefits (Costs) by State for Retail Customers of Investor-Owned Utilities under the SPP Tariff
(in millions of 2006 present value dollars; positive numbers are benefits)

Original

Arkansas	9.2
Louisiana	(3.8)
Kansas	8.3
Missouri	60.0
New Mexico	9.2
Oklahoma	141.7
Texas	26.6

Revised

Arkansas	8.5
Louisiana	(3.8)
Kansas	26.4
Missouri	41.7
New Mexico	9.2
Oklahoma	141.1
Texas	26.6