RSC AGENDA

REGULAR MEETING*
Monday, April 23, 2007
1:00-5:00 p.m.
The Skirvin Hilton Hotel
Oklahoma City, OK

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a quorum
   b. Adoption of January 29 and March 1, 2007 Minutes

3. UPDATES
   a. RSC Financial Report
   b. Other RSC Officer Reports
   c. FERC
   d. SPP

4. BUSINESS MEETING (ALL ITEMS SUBJ ECT TO DISCUSSION AND ACTION)
   a. CAWG Report ................................................................. Mr. Mike Proctor
      - Waiver Timing in relation to: State Regulatory Proceedings, SPP Tariff Implications, Project Timelines. (discussion item)
      - OMPA Waiver Request (action item)
      - AECC Waiver Request (action item)
      - Alternative Approaches to Economic Upgrades
   b. RSC bylaws and Travel Policy Draft Revisions (action item) ...... Commissioner Hochstetter
   c. 2006-2016 STEP Unintended Consequences Review ................................. Dennis Reed
   d. Transmission Project Tracking ......................................................Les Dillahunty
   e. EIS Market Status .................................................................................... Carl Monroe
   f. SPP Organizational Metrics Review ..................................................... Michael Desselle
   g. Overview of FERC Order 890 ....................................................................Les Dillahunty

5. SCHEDULING OF NEXT REGULAR MEETING, SPECIAL MEETINGS OR EVENTS

6. ADJOURNMENT

* Background materials will continue to be posted in advance of the scheduled meeting as they become available.
Southwest Power Pool
REGIONAL STATE COMMITTEE
Hilton Palacio Del Rio
January 29, 2007

• MINUTES •

Administrative Items:
Members in attendance or represented by proxy were:
   Julie Parsley, Public Utility Commission of Texas (PUCT)
   Brian Moline, Kansas Corporation Commission (KCC)
   Sandra Hochstetter, Arkansas Public Service Commission (APSC)
   Denise Bode, Oklahoma Corporation Commission (OCC)
   Steve Gaw, Missouri Public Service Commission (MPSC)

There were 59 in attendance (Attendance & Proxies – Attachment 1). Others in attendance via phone:
   Sedina Eric, FERC
   Walter Wolf, Stone, Pigman, Walther, Wittman, LLC
   Bary Warren, Empire District

President Parsley called the meeting to order at 1:20 p.m. Cheryl Robertson called roll and a quorum was declared. President Parsley asked for adoption of the October 23, 2006 meeting minutes (RSC Minutes 10/23/06 - Attachment 2). President Parsley asked for a show of hands to approve the October 2006 minutes as presented. Hearing no addition or corrections, the October minutes were approved.

Updates:
RSC Financial Report
Les Dillahunty (SPP) presented the RSC Financial Report (RSC Financial Report – Attachment 3). Mr. Dillahunty reported that the RSC remained well under budget for 2006 in large part due to the fact that no cost/benefit studies were conducted. The bulk of expenses incurred for 2006 were meeting and travel expenses.

RSC Officer Reports
President Parsley asked for RSC officer reports. No reports were offered.

FERC Update
John Rogers provided an update on FERC activities:
   • The Commission issued SPP’s Market Readiness Certification Order on Friday, January 26.
   • The Commission will convene a conference on its market monitoring policies on April 5 in Washington, D.C.
   • The first Demand Response conference was held in Miami at the NARUC annual meeting in November.
   • The first in a series of conferences will be held at the Commission to examine the state of competition in wholesale power markets on February 27.
   • Two significant rule makings are currently before the Commission: 1) the Open Access Transmission Tariff reform and 2) the Market Based Rates.
   • All were invited to visit the FERC website, which now provides electric market information overviews for the nation as well as regional markets, including all of the RTO/ISOs.
SPP Update
Nick Brown provided an update on SPP activities. Mr. Brown stated that SPP had received a FERC Order on Friday, January 26, affirming a February 1 EIS market start. From SPP's prospective, market go live February 1 will be treated with minimal public fanfare culminating much hard work and testing by market participants and SPP. A Go/No Go Task Force was formed as a FERC requirement to follow the transition process. This task force will meet at 2:00 p.m. today and 2:00 p.m. tomorrow, January 31, to make its final recommendation on launching the market. Should the group choose not to go live, Mr. Brown would call a SPP Board of Directors/Members Committee meeting to aid in making the final decision.

Mr. Brown updated the group regarding NERC’s transition to an Electric Reliability Organization (ERO). The 60 day period for FERC’s response to NERC’s ERO implementation status and SPP’s RE status ends on March 10. Billings have gone out to RE’s under the new organization using a different mechanism with costs being isolated from SPP’s budget. Commissioner Hochstetter requested that FERC continue to monitor and provide follow up information on the NERC budget. SPP’s first initiative after receiving RE status will be to modify the Bylaws to elect three trustees to oversee the Standard setting process and the compliance process. This means that SPP must transition quickly following the receipt of the order. Mr. Brown expressed appreciation of the RSC’s support of SPP’s RE model.

SPP has formed an Organizational Metrics Task Force to provide a corporate dashboard in order to illustrate the status of SPP at a glance. This Task Force consists of Directors and Members representatives who will develop a straw proposal and solicit feedback. Organizational Metrics are important in transitioning from a small company to a large company.

Mr. Brown mentioned two other initiatives that are in place: 1) a comprehensive review of the funding mechanism for economic upgrades and 2) the EHV Transmission Study Overlay.

Business Meeting:
CAWG Report
Dr. Mike Proctor provided a review of the CAWG White Paper on Attachment Z, OG&E and Westar waivers, and the alternative approaches to economic upgrades. Dr. Proctor explained the background of Attachment Z, which has been sent to the RTWG with recommendations in order to craft Tariff language to address aggregate study concerns.

The MOPC asked CAWG to review the Westar waiver prior to the SPP Board of Directors meeting on January 30. CAWG recommended to the Markets and Operations Policy Committee (MOPC) to move forward with the waiver request from OG&E as recommended by SPP.

Dr. Proctor provided a review of alternative approaches to economic upgrades developed as a directive from the RSC at its October 2006 meeting (Alternative Approaches – Attachment 4). Four alternative approaches were presented and explained: 1) portfolio approach, 2) higher voltage emphasis, 3) benefit metrics, 4A) severe congestion; and 4B) final determination of cost allocation should wait until the SPP has developed a region-wide portfolio. Discussion was in favor of a parallel approach with SPP developing a portfolio of economic projects with region-wide benefits with the RSC to determine a recommendation on cost allocation.

Regional Transmission Working Group’s Unintended Consequences Review
Dennis Reed provided a report on unintended consequences (RTWG Report – Attachment 5). Mr. Reed reviewed the current methodology of allocating cost from the Base Plan Upgrades, the time line reviewing the zonal allocation process, and the proposed methodology. He reported the task force results. The RTWG agreed with the task forces and presented the RSC with the following recommendation:

The RSC accept the RTWG recommendations
1. Change the inter-zonal cost allocation process from “The sum of the Net MW-Mile impacts” to “The sum of the Positive MW-Mile impacts”.
2. A minimum allocation of $100,000 to a zone be implemented.
3. Directs the CAWG to give further consideration to altering the existing regional/zonal
allocation percentages and/or allocation methods for Base Plan Funded projects to encourage the construction of high voltage projects that have both economic and reliability benefits.

This Recommendation and tariff language was approved by the MOPC at their last meeting.

Following discussion, Sandra Hochstetter moved to adopt parts 1 & 2 but not part 3. Denise Bode seconded the motion, which passed unanimously.

Transmission Expansion Plan, Transmission Overlay Assessment, & Westar Waiver Request
Jay Caspary provided an SPP engineering staff report (Engineering Report – Attachment 6).

SPP Transmission Expansion Plan (STEP)
Mr. Caspary provided an overview of the STEP process including a summary of transmission projects from 2006 through 2016; recommendations for Board of Directors approval to approve the plan and to authorize and direct the start of construction projects listed in Appendix B. Mr. Caspary also reviewed Base Plan Upgrades (Base Plan Upgrades – Attachment 7), economic projects, and other transmission expansion studies. President Parsley requested that an SPP provide a Base Plan Upgrade project status chart for every meeting so that RSC can help address problems and work with SPP as a team.

Supply Adequacy Audit
This audit was last performed in 1999 and will be performed again in the first quarter of 2007 coincident with the EIA-411 data collection efforts.

SPP EHV Overlay Assessment
With the STEP process in place, SPP Staff working through the Transmission Working Group (TWG) wanted to identify a long range vision for the bulk power transmission network with input from an independent entity with EHV experience. Monies have been budgeted and approved for EHV Overlay contractors. IntraSource Technology and PowerWorld Corporation have been selected as contractor The process will include a timeline and milestones with completion slated for mid-2007. Support of members and stakeholders will be appreciated throughout the assessment.

Westar Waiver Request
Mr. Caspary provided background regarding the Westar waiver request. This request was reviewed by CAWG who provided unanimous support. The MOPC approved SPP Staff’s recommendation to provide full Base Plan funding of the Rose Hill – Sooner 345 kV project. RSC’s approval was requested. Sandra Hochstetter moved to approve the Westar waiver request. Brian Moline seconded the motion, which passed unanimously. The secretary was reminded that RSC action does not prejudge any case that may come before a state regulatory agency.

2006 Regional State Committee Audit Results
Sandra Hochstetter stated that the RSC Bylaws require an annual financial audit (RSC Audit – Attachment 8). Patricia Salman & Associates were contracted to perform an audit of the year ending December 31, 2005. Only one exception was found regarding travel reimbursement. Mileage reimbursement levels were not well documented. Ms. Hochstetter offered copies of the audit for review.

2006 SPP Board of Directors Evaluation Results and Stakeholder Satisfaction Survey Results
Les Dillahunty provided the results of the SPP Board of Directors Evaluation and Stakeholder Satisfaction Survey (BOD Evaluation & Stakeholders Survey – Attachment 9). This is the third year for the Board of Directors Evaluation and the second year for the Stakeholder Satisfaction Survey.

Organizational Metrics Overview and SPP Emergency Response Plan
Les Dillahunty reported that Michael Desselle was currently meeting with the Organizational Metrics Task Force and that he would provide the report. Mr. Dillahunty stated that the organization metrics would be reported at the next RSC meeting and that it is important that the RSC understand these metrics and what’s
Regional State Committee
January 29, 2007

behind them.

Mr. Dillahunty then reviewed the SPP Emergency Response Plan (SPP Emergency Response Report - Attachment 10). The plan’s major areas of focus are:

- Internal Coordination
- Crisis Communication
- Information Systems Incident Response
- Emergency Situations
- Building Evacuation (all employees)
- Operations Evacuation to Backup Center
- Power System Restoration

Denise Bode requested that contact information be provided for review for her state. Other RSC members requested the same. Mr. Dillahunty said that this information would be delivered next week.

EIS Market
Carl Monroe provided a report on the SPP EIS Market due to go live on February 1. Mr. Monroe stated that FERC issued its SPP Market Readiness Certification Order on Friday, January 26, declining to delay the start of SPP’s imbalance market scheduled for February 1. There have been daily market reports since last Thursday and the transition started in earnest 4 days ago. All Market metrics from October through December have been completed. There have been some concerns expressed regarding the late arrival of model changes, settlement data feeds, LIP volatility, etc. but some things will only be learned after going live.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President Parsley noted that the next regularly scheduled RSC meeting is in Oklahoma City, Oklahoma on April 23-24, 2007.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty
Southwest Power Pool
REGIONAL STATE COMMITTEE
March 1, 2007
Teleconference

• M I N U T E S •

Administrative Items:
Members in attendance or represented by proxy were:
    Julie Parsley, Public Utility Commission of Texas (PUCT)
    Brian Moline, Kansas Corporation Commission (KCC)
    Sandra Hochstetter, Arkansas Public Service Commission (APSC)
    Denise Bode, Oklahoma Corporation Commission (OCC)
    Steve Gaw, Missouri Corporation Commission (MPSC)

Others in attendance:
    Tom DeBaun, Kansas Corporation Commission
    Robert Krehbiel, Kansas Corporation Commission
    Matthew Tomc, Kansas Corporation Commission
    Bridget Headrick, Public Utility Commission of Texas
    Adrianne Brandt, Public Utility Commission of Texas
    Joyce Davidson, Oklahoma Corporation Commission
    Mike Proctor, Missouri Corporation Commission
    Greg Meyer, Missouri Public Service Commission
    Sam Loudenslager, Arkansas Public Service Commission
    Ted Thomas, Arkansas Public Service Commission
    Harry Skilton, SPP Director
    Jeff Knottek, City Utilities of Springfield
    Mel Perkins, OG&E
    Phillip Crissup, OG&E
    David Douglas, Aquila, Inc.
    Tong Ingram, FERC
    Sedina Eric, FERC
    Walter Wolf, Stone, Pigman, Wittman, LLC
    Les Dillahunty, Southwest Power Pool, Inc.
    John Mills, Southwest Power Pool
    Nick Brown, Southwest Power Pool
    Carl Monroe, Southwest Power Pool
    Richard Dillon, Southwest Power Pool
    Cheryl Robertson, Southwest Power Pool

President Parsley called the meeting to order at 1:10 p.m. Roll was called and a quorum declared.

Business Meeting:
Dr. Mike Proctor discussed cost allocation alternatives and the process for the Cost Allocation Working Group (CAWG) and the RSC (Presentation – Attachment 1). Two basic components are involved: content and schedule of meetings. He called attention to schedule considerations hoping to complete cost allocation alternatives by the July 2007 RSC meeting and the final policy determination to be made by the October 2007
Regional State Committee
March 1, 2007

RSC meeting. Dr. Proctor stated that it may be beneficial to hold a summit the morning of the July RSC
meeting to discuss the benefit of alternative cost allocation. Currently the plan is to hold monthly CAWG
meetings with follow-up recommendations to the RSC. Ms. Hochstetter suggested having presentations from
multiple stakeholders at meetings rather than limiting it to the CAWG as all would benefit from the dialog much
as in the Base Plan discussions.

Les Dillahunty explained that the OG&E waiver, due to an administrative oversight in January, there was no
formal action taken by the RSC (OG&E Waiver – Attachment 2). Mr. Dillahunty stated that the CAWG had
agreed the monetary amount was reasonable and recommended the approval of the waiver but the CAWG did
not agree with the SPP staff assumptions included in their recommendation. The Markets and Operations
Policy Committee approved the waiver during its January, 2007 meeting and the SPP Board of Directors
approved the waiver on January 30, 2007 contingent upon the RSC’s endorsement. Sandra Hochstetter
moved to approve and Denise Bode seconded the motion. The motion passed unanimously.

Mr. Dillahunty reviewed possible modifications of the RSC Bylaws and Travel Policy (RSC Bylaws and Travel
Policy – Attachment 3).

- Article IX, Section 4 of the RSC Bylaws regarding approved signatures is not being followed. It was
  suggested that the paragraph be revised to conform with the current practices.
- Sandra Hochstetter suggested a new Article IX, Section 5 to read:
  DELEGATED AUTHORITY. For routine payment of meeting and travel expenses incurred by SPP
  RSC Members and their designees, including designated State Commission Staff members, the SPP
  RTO may act as agent for the RSC and make payment of such expenses in accordance with the
  RSC’s then-current Expense Reimbursement Policy. Such expenses shall be paid from the RSC’s
  approved Budget. For items of a non-routine and more financially significant nature, such as an RSC-
  commissioned cost-benefit study or a large conference or event, the RSC Board of Directors may
  provide approval to the appropriate person within the SPP RTO to pay for such expense, acting as
  agent for the RSC. Commissioner Hochstetter will check language with groups similar to the RSC
  and report back.
- Mr. Dillahunty reviewed the Travel Policy stating the number of state commission regulatory staff to be
  reimbursed from one state for attendance at the same SPP meeting. Several ideas were discussed.
  Mr. Dillahunty will work with Commissioner Hochstetter to develop draft revisionary language for the
  April meeting.
- Mr. Dillahunty addressed the practice of whether or not to allow e-mail (as opposed to in-person or
  conference call) votes on non-substantive, non-critical matters. Following discussion, it was decided
to develop language to add to the Bylaws.
- Mr. Dillahunty inquired if it would be better to extend the deadline from 30 days to 60 days in regards
  to submitting expenses for reimbursements. It was suggested that this flexibility would be beneficial.
  This change will be added to the draft Bylaws changes.
- Sandra Hochstetter stated that the audit presented for approval at the January meeting was for the
  year 2005. It is now time to retain an auditor for 2006. She moved to retain the same auditor as used
to perform the 2005 Audit. Steve Gaw seconded the motion, which passed unanimously. It was
decided that at the first meeting of the calendar year the policy should be for the Secretary/Treasurer
to suggest the retention of an auditor.

Scheduling of Next Regular Meeting, Special Meetings or Events:
President Parsley noted that the next regularly scheduled RSC meeting is in Oklahoma City, Oklahoma on

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty
Southwest Power Pool
REGIONAL STATE COMMITTEE
April 5, 2007
Teleconference

• M I N U T E S •

Administrative Items:

Members in attendance or represented by proxy were:

- Julie Parsley, Public Utility Commission of Texas (PUCT)
- Brian Moline, Kansas Corporation Commission (KCC)
- Sandra Hochstetter, Arkansas Public Service Commission (APSC)
- Denise Bode, Oklahoma Corporation Commission (OCC)
- Steve Gaw, Missouri Corporation Commission (MPSC)

Others in attendance:

- Tom DeBaun, Kansas Corporation Commission
- Larry Holloway, Kansas Corporation Commission
- Don Low, Kansas Corporation Commission
- Matthew Tomc, Kansas Corporation Commission
- Joyce Davidson, Oklahoma Corporation Commission
- A.J. Ferate, Oklahoma Corporation Commission
- Mike Proctor, Missouri Public Service Commission
- Greg Meyer, Missouri Public Service Commission
- Harry Skilton, SPP Director
- David Fliescher, Secretary of Energy (Oklahoma)
- Bobby Wegener, State of Oklahoma
- David Kays, OG&E
- Jake Langthorn, OG&E
- Rob Janssen, Redbud Energy
- Dennis Reed, Westar Energy
- John Olsen, Westar Energy
- Robin Morecroft, Oklahoma Municipal Power Authority
- Richard Spring, Kansas City Power and Light
- Alan Myers, ITC Great Plains
- Walter Wolf, Stone, Pigman, Walther, Wittman, LLC
- Les Dillahunt, Southwest Power Pool, Inc.
- John Mills, Southwest Power Pool
- Nick Brown, Southwest Power Pool
- Carl Monroe, Southwest Power Pool
- Cheryl Robertson, Southwest Power Pool

President Julie Parsley called the meeting to order at 10:05 p.m. Introductions were made and a quorum was declared.

Business Meeting:

Dr. Mike Proctor provided a report from the Cost Allocation Working Group (CAWG) meeting on March 28,
Regional State Committee  
April 5, 2007  

2007 (CAWG Report – Attachment 1). Topics included were:

- **Unintended Consequences**: SPP Staff found no unintended consequences in the 2006 Transmission Expansion Plan and presented 4 methods for treating losses in the MW-mile calculation.

- **Transmission Expansion Portfolio**: SPP presented a hypothetical portfolio using 6 projects within the SPP footprint and compared four allocation methods based on peak hour flows. A discussion was held regarding the relationship of a portfolio of transmission projects to the EHV plan. The CAWG asked that future analysis include a broader base than the peak hour.

- **Benefit to Cost Ratio of Inclusion of Upgrades for Cost Allocation**: Dr. Proctor presented a strawman proposal to require estimated benefits to exceed estimated costs by a factor of 1.67. It was decided that Dr. Proctor would circulate questions and topics for discussion by stakeholders on the benefit cost ratio at the April 23 RSC meeting.

- **Waiver Requests from AECC, OMPA, AEP and SUM**: Two Turk Plant participants have requested waivers: AECC and OMPA. Due to open dockets in several states regarding the construction of this plant, it was decided that a generic discussion on processes for waiver requests should be included in the April agenda. Commissioners can excuse themselves if necessary when specific cases are discussed. Les Dillahunty will prepare a strawman from SPP Staff in order to have a dialog with commissioners and stakeholders at the April RSC meeting regarding waiver requests.

- **ITC Great Plains presentation**: ITC presented hurdles for investment in new transmission within the SPP region.

Steve Gaw inquired on how growth of wind generation is impacting capacity, operating reserves, and ancillary services. Les Dillahunty will research this and include information in SPP’s April report to the RSC.

**Scheduling of Next Regular Meeting, Special Meetings or Events:**
The next regularly scheduled RSC meeting is in Oklahoma City, Oklahoma on April 23, 2007.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty
Regional State Committee  
For the Three Months Ending March 31, 2007  
Budget vs. Actual  
DRAFT

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<td>Other Income</td>
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<td><strong>Total Income</strong></td>
<td>39,796</td>
<td>142,376</td>
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| **Expense**    |             |            |          |
| Travel         | 16,313      | 24,501     | (8,188) |
| Meetings       | 21,277      | 17,500     | 3,777    |
| Administrative | -           | 375        | (375)    |
| Outside Services | 2,207      | -          | 2,207    |
| Cost Benefit Studies | -         | 100,000    | (100,000) (B) |
| **Total Expense** | 39,796      | 142,376    | (102,580) |

|                |             |            |          |
| **Net Income (Loss)** | -         | -          | -        |

(A) YTD revenue is less than budget given that ytd expenses are less than budget.
(B) YTD study costs are less than budget as no studies have been conducted in 2007.
Aggregate Study/State CCNs

- The Aggregate Study Process, which includes the waiver request process, considers a number of transmission service requests and transmission upgrade alternatives before concluding with a final Facilities Study that allocates costs among study participants based upon MW impact.

- The results of the Aggregate Study Process and any Waiver requests provide state regulatory commissions with: (1) more definitive information regarding the "need" for a particular transmission project, (2) a higher degree of certainty regarding the "reasonableness" of a proposed transmission project, and (3) more definitive cost and cost allocation information associated with a transmission project.

- The failure to secure necessary state regulatory approval(s) for a project may significantly alter other projects in the Aggregate Study and the associated cost allocation, irrespective of any waiver request.

Aggregate Study/State CCNs (cont.)

- Deferral of action on projects arising from the Aggregate Study Process or on a waiver request pending the conclusion of a state CCN proceeding(s) may cause the Aggregate Study Process to be populated by "placeholder" projects or cause parties to encounter delays imposed by entering the Aggregate Study Process after a CCN has been granted.

- Early entrance into the Aggregate Study process may provide important information to state regulators and the affected parties, with any resulting Service Agreement(s) being made contingent upon necessary CCN approval(s).
Organizational Roster
The following members represent the Southwest Power Pool

Les Dillahunty, Vice President, Regulatory Policy
Pat Bourne, Director, Transmission Policy
Jay Caspary, Director, Engineering
John Mills, Manager, Tariff Studies

Background

Attachment J of the SPP Tariff addresses recovery of costs associated with new transmission facilities. Subsection III of this section addresses Base Plan funding for network upgrades, including Safe Harbor Cost Limit of $180,000/MW, and provides for waivers, whereby application may be made for additional Base Plan funding for a network upgrade in excess of the Safe Harbor Limit based on three independent factors.

On January 31, SPP received a request for waiver under Attachment J of the SPP Tariff for costs in excess of the Safe Harbor Cost Limit for Base plan funding from Arkansas Electric Cooperative Corporation (AECC) and from Oklahoma Municipal Power Authority (OMPA) for new Designated Resources of 70 and 41 MW respectively, based on the upgrade costs associated with transmission from the Turk Power Plant. SPP’s 120-day deadline under Attachment J is May 31, 2007. The next regularly scheduled Board of Directors meeting is April 24, 2007.

Analysis

AECC and OMPA requested a waiver based upon Section III.C.2.ii of Attachment J for a reservation of 20 years. The 20 year reservations and the commitment to the life of the Turk Power Plant justify full Base Plan funding for the required upgrades to facilitate the transmission for AECC and OMPA new Designated Resource.

Both waiver requests have been discussed in the February and the March meetings of the CAWG. Based on the discussion held in these meetings, the CAWG is recommending that the SPP RSC recommend to the SPP Board of Directors to grant the waiver requests for AECC and OMPA. The RTWG held a brief discussion of the AECC and OMPA waiver requests at their March meeting but took no action.

Recommendation

The recommendation of SPP Staff is to provide waivers of such extent that the projects required for the AECC and OMPA new designated resources are fully Base Plan funded.

Approved: Markets & Operations Policy Committee April 11, 2007
One No Vote – KCPL

Action Requested: Approval of AECC and OMPA waiver requests

Attachments: Waivers requests and response letters
January 31, 2007

Mr. John Mills  
Southwest Power Pool  
415 N. McKinley, 140 Plaza West  
Little Rock, AR 72205

Subject: Request for waiver of Base Plan Funding limits of the SPP OATT Attachment J, Section III B for OASIS Request #1161209

Dear John:

Arkansas Electric Cooperative Corporation (AECC) seeks Base Plan Upgrade Cost treatment of the required upgrades to the extent they exceed the Safe Harbor Cost Limit. A request for waiver is provided for in Attachment J, Section III C of the SPP OATT.

OASIS request # 1161209 is for 70 MW of transmission service from the Turk coal plant to AECC’s load within the SPP.

Under the Tariff this 70 MW reservation is eligible for Base Plan Funding of up to $12,600,000 ($180,000 times 70 MW). Based on 2006-AG3-AFS-1, the Engineering and Construction Cost Allocated to AECC for this reservation is estimated at $13,829,229.

The circumstances of this capacity addition meet the two conditions set forth in the Tariff that allow the Waiver request. First, Section III C.2.i provides for a waiver based on the term of service exceeding the minimum requirement of five (5) years. This reservation is for a 20-year term of service. Second, a waiver may be requested if the capacity in question does not cause the Market Participant’s total resources to exceed 125% of its firm load obligation. In 2011, the in service date of the Turk Plant and the effective date of OASIS Request #1161209, AECC will be importing generation to serve its load in the SPP. The 70 MW will offset a portion of the use of plants outside of the SPP with generation inside the SPP. Even with the addition of this 70 MW, AECC’s total resources will be less than 125% of its firm load obligation.

One of the benefits provided by the upgrades related to this plant is the strengthening of the transmission ties between the SPP and Entergy. One of the lines listed is a 345 kV transmission line between the Turk Plant and Entergy’s McNeil 500 kV substation. This
Mr. John Mills  
January 31, 2007  
Page 2

will provide greater reliability and the opportunity for additional competition within the SPP.

If you have any questions on this waiver request please do not hesitate to contact me.

Sincerely,

Ricky Bittle  
Vice President  
Planning, Rates & Dispatching

RB: lh

c: Gary Voigt
March 2, 2007

Mr. Ricky Bittle
Vice President; Planning, Rates & Dispatching
Arkansas Electric Cooperative Corporation
1 Cooperative Way
Little Rock, AR 72219-4308

Subject: Request for Waiver under OASIS reservation # 1161209

Dear Mr. Bittle:

The request for a full or partial waiver submitted by AECC is based on a twenty year term of service. In order to facilitate our evaluation of this waiver request, SPP requests AECC’s cooperation in working through this process by providing an explanation of the factors used by AECC in determining the length of transmission service request, including a detailed explanation as to why those factors should qualify the project for full Base Plan funding. Please also provide documentation substantiating the 20 year ownership based on the reservation request.

Please provide a detailed explanation of the importing Designated Resources that are being used currently that may be temporarily or permanently undesignated due to the addition of the Turk 70 MW new Designated Resource.

SPP has now posted SPP-2006-AG3-AFS-2. Based on this revised posting for the remaining Customers in the study queue, please provide SPP an explanation of the regional benefit analysis AECC used to determine that full Base Plan funding will benefit the SPP region and how these interconnections will provide reliability and the opportunity for additional competition within the SPP footprint.

To assist SPP in constructing the overall case regarding the waiver request, SPP requests information on the projected fuel mix of AECC in the year prior to this unit’s operation as compared to the fuel mix during the first full year after commercial operation.

Robert Shields made a presentation to the Cost Allocation Working Group (CAWG) on February 21, 2007, addressing this waiver request. During that discussion, plant owners
referenced the additional costs, not included in the waiver request, incurred by AECC and others associated with the interconnection of the unit to the grid. While that information may not be influential in terms of the waiver request, we believe that information to be relevant and would like to capture those points for the record that will accompany SPP’s recommendation on the waiver request.

Please provide the above requested data no later than March 16th to allow SPP to review the data provided and to formulate a report to the CAWG/RTWG for recommendation to the MOPC in accordance with the tariff requirements.

Thank you.

Sincerely,

John E. Mills, P.E.
Manager, Tariff Studies
Southwest Power Pool
cc: Gary Voigt
    Les Dillahunty
    Pat Bourne
    Jay Caspary
Lighting the Past…Powering the future
March 13, 2007

John Mills
Southwest Power Pool
415 N. McKinley St., Suite 140
Little Rock, AR  72205-3020

Dear John:

In your letter of March 2, 2007, you asked for additional information regarding AECC’s request that all transmission investment directly assigned to AECC, related to AECC’s transmission service request OASIS # 1161209, be included as base plan funding. AECC’s request was based on the Southwest Power Pool Tariff, Attachment J Section III C.2.ii.

The SPP aggregate studies first showed required investment related to AECC’s 70 MW request of SPP2006-AG2-AFS-2 $13,829,229 and then SPP2006-AG3-AFS-2 $16,025,758. Of this amount, $12,600,000 would be eligible for base plan funding without a waiver request.

In your letter you requested the following information:

Reason for the length of the reservation

AECC has an obligation to serve its members. AECC must make long term commitments in order to try and minimize the cost to consumers.

AECC intends to own a portion of the Turk Power Plant for the entire life of the power plant. The normal life expectancy of a power plant is in excess of 35 years. AECC does not expect the life of the Turk Power Plant to be any less. At some point, AECC will extend the reservation to the life of the power plant.
John Mills  
March 13, 2007  
Page 2

Why the factors should qualify the project for Base Plan Funding

AECC has an obligation to serve its member’s load. This plant will become one plant in AECC’s portfolio of resources. This plant will allow AECC to use coal energy to displace natural gas.

As a Network Service Customer, AECC will be serving load over the life of the reservation and beyond. As AECC’s load grows, the amount that AECC pays in transmission service charges will also grow. Within the SPP area, AECC’s load is currently forecast to grow at approximately 40 MW/year. At this projected growth rate, this reservation represents less than two years load growth.

As a Network Service Customer, AECC’s loads and resources are to be taken into account in all planning. Once the transmission required for this reservation is in place all future transmission additions will be made with this required transmission as part of the base case.

Document Ownership

AECC entered into a letter of intent to participate in the ownership of the Turk Power plant dated October 11, 2006 and currently is in negotiations with AEP to finalize an ownership agreement.

Importing Designated Resources that might temporarily be un-designated

AECC’s resources used to provide energy for projected schedules out of the Entergy Arkansas, Inc. (EAI) system are covered under a grandfathered contract with EAI. AECC’s contract gives AECC the right to schedule from its fleet of resources. The inclusion of the Turk Plant as a Designated Resource on the SPP transmission system could allow AECC to reduce the schedule from EAI to SWEPCO.

AECC does not anticipate un-designating any resources. However, if AECC un-designates any resources, it would only be on a temporary basis. The 70 MW at the Turk Plant would become available to AECC in 2011 and would represent only 2 years of load growth, in any event.
Regional benefit analysis – additional reliability and competition

AECC has not attempted to quantify the regional benefit referenced in the request for waiver. Given the excess generation in the Entergy area, it is obvious that the addition of a 345 kV interconnection between EAI and SWEPCO would increase the ATC and therefore increase access for additional competition. It is also reasonable to assume that the addition of a 345 kV interconnection between the SPP and EAI would bring additional reliability benefits.

AECC fuel mix 2010 and 2011

Information in MW

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2011</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SWEPCO</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>264</td>
<td>334</td>
</tr>
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<td>Gas</td>
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<td>324</td>
</tr>
<tr>
<td>Hydro</td>
<td>17</td>
<td>17</td>
</tr>
<tr>
<td>Schedule from EAI</td>
<td>345</td>
<td>279</td>
</tr>
<tr>
<td>Schedule from SPA</td>
<td>89</td>
<td>89</td>
</tr>
<tr>
<td><strong>SPA</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Schedule to SWEPCO</td>
<td>89</td>
<td>89</td>
</tr>
<tr>
<td>Schedule to EAI</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Schedule from EAI</td>
<td>76</td>
<td>78</td>
</tr>
<tr>
<td><strong>EAI</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Coal</td>
<td>1168</td>
<td>1168</td>
</tr>
<tr>
<td>Gas</td>
<td>804</td>
<td>804</td>
</tr>
<tr>
<td>Hydro</td>
<td>52</td>
<td>52</td>
</tr>
<tr>
<td>Schedule to SWEPCO</td>
<td>345</td>
<td>279</td>
</tr>
<tr>
<td>Schedule to SPA</td>
<td>76</td>
<td>78</td>
</tr>
</tbody>
</table>

AECC owns or purchases generation in three areas, in order to minimize cost to its members; it requires the ability to move capacity and energy between areas.

Additional cost

The discussion regarding additional cost incurred by the plant owners referred to the Generation Impact Study for the Turk Power Plant, GEN-2006-010. The study shows the
need for $92,850,000 in investment on the AEP system to allow the interconnection of the power plant. The study includes only minimal cost for impact on the facilities of the cooperatives that serve load in the area.

If you need additional information please call me.

Sincerely,

Ricky Bittle
Vice President
Planning, Rates & Dispatching

RB:lh

xc: Gary Voigt
    Keith Sugg
January 31, 2007

Mr. John Mills
Southwest Power Pool
415 N, McKinley, 140 Plaza West
Little Rock, AR  72205

Subject: Request for waiver per Attachment J of the SPP OATT for OASIS Request #1159596

Dear John,

As provided for in Attachment J, Section III.C.1.ii of the SPP OATT, the Oklahoma Municipal Power Authority is submitting this request for waiver with respect to OASIS request # 1159596. Specifically, OMPA seeks Base Plan Upgrade Cost treatment of the required upgrades to the extent they exceed the Safe Harbor Cost Limit.

OASIS request # 1159596 pertains to OMPA’s 41 MW ownership share of the 600 MW Turk coal plant to be located in Hempstead County, Arkansas. The reservation is for 41 MW from CSWS to CSWS beginning in 2011 through 2031, a 20-year period. Under the Tariff this 41 MW reservation is eligible for one-time Base Plan Funding totaling $7,380,000 ($180,000 times 41 MW).

Based on 2006-AG3-AFS-1, the Engineering and Construction Cost Allocated to OMPA for this reservation is estimated at $8,597,956. The result is that the cost for OMPA’s portion of the necessary upgrades for the Turk plant is $1,217,956 greater than the allowable Base Plan Funding. It is for the additional cost, beyond the $7,380,000, that OMPA is seeking waiver.

Section III.C.2.ii provides for a waiver based on the term of service exceeding the minimum requirement of five (5) years. This reservation is for a 20-year term of service thus far exceeding the requirements of Section III.C.2.ii. Further, even the twenty-year length of the reservation understates the length of OMPA’s commitment to the resource. While the OASIS request is listed as a 20-year reservation, the plant itself and OMPA’s ownership rights in the plant are expected to continue for at least 35 years. Thus the investment should be viewed as supporting a very long-term use of the system.

OMPA’s plan to meet a significant portion of its future load requirements by acquiring a portion of the Turk power plant, supported by a very long term transmission reservation, will facilitate SPP’s ability to efficiently plan the system for the region’s long term needs and will result in significant savings to SPP. OMPA is committing to a single 20-year
DNR reservation for the Turk plant rather than seek individual 5-year reservations for various DNRs, over the same 20-year period. Had OMPA chosen to obtain a series of individual 5-year DNRs (each 41 MW), SPP would have to plan for each such resource and OMPA would, in each case, be eligible for base plan funding of $7,380,000. Thus SPP's exposure for base plan funding for this 41 MW portion of OMPA's load over the 20-year period would be $36,900,000. With the single Turk plant reservation, SPP's exposure will be limited to the $7,360,000 plus the waiver amount or a total of approximately $8,597,956.

OMPA's waiver request provides greater regional value than previous waiver requests that have been for peaking or intermittent generation, and does so at lower cost to other SPP ratepayers. OMPA's waiver request amounts to approximately $29,706/MW, while recent waiver requests pertaining to peaking generation have required roll-in of an additional $63,504/MW.

Finally, we note that waiver is particularly appropriate to avoid discrimination against smaller systems, a concern expressed by FERC in approving the $180,000/MW Safe Harbor in combination with the 125% limitation. OMPA should not be discriminated against simply because its small size dictates relatively small commitments in order to achieve diversity and manage risks.

There will likely be as of yet quantified, third party benefits resulting from construction of the required transmission improvements. However, granting this waiver will relieve SPP of tracking revenue credits that might otherwise be earned by OMPA as a result of third party benefits.

OMPA also has reservation #1162095 included in 2006-AG3-AFS-1, this reservation is for 73 MW from OKGE to OKGE. The Engineering and Construction Cost Allocated to OMPA for this reservation is $7,515,287. However, the reservation could be eligible for base plan funding of up to $13,500,000 at the current rate of $180,000 per MW. OMPA believes it would be reasonable to apply a portion of the unused base plan funding for reservation #1162095 to reservation #1159596.

It is for the above stated reasons that OMPA seeks this waiver. Should you have any questions on this request please do not hesitate to contact me.

Sincerely,

Robin J. Morecroft. P.E.
Director of Engineering Services

Cc: C.Holman
    T.Littleton
    H.Dawson
March 2, 2007

Mr. Robin J. Morecroft PE
Director of Engineering Services
Oklahoma Municipal Power Authority
2300 East Second St.
Edmond, OK 73083-1960

Subject: Request for Waiver under OASIS reservation # 1159596

Dear Mr. Morecroft:

The request for full or partial waiver submitted by OMPA is based on a twenty year term of service. In order to facilitate our evaluation of this waiver request, SPP requests OMPA’s an explanation of the factors used by OMPA in determining the length of transmission service, including a detailed explanation as to why those factors should qualify the project for full Base Plan funding. Please also provide documentation for the 35 year ownership noted in your letter.

Please provide a detailed explanation of how this “very long term transmission reservation, will facilitate SPP’s ability to efficiently plan the system for the region’s long term needs and will result in significant savings to SPP”.

SPP has now posted SPP-2006-AG3-AFS-2. Based on this revised posting for the remaining Customers in the study queue, please provide an explanation of the regional benefit analysis OMPA has used to determine that full Base Plan funding will benefit the SPP region and how these interconnections will provide regional value for peaking or intermittent generation, and how this will accomplish lower costs to other ratepayers.

To assist SPP in constructing the overall case regarding this waiver request, SPP requests information on the projected fuel mix of OMPA in the year prior to this unit’s operation as compared to the fuel mix during the first full year after commercial operation.

Gene Anderson made a presentation to the Cost Allocation Working Group (CAWG) on February 21, 2007, addressing this waiver request. During that discussion, Gene
referenced the additional costs incurred by OMPA associated with the interconnection of the unit to the grid which were not included in the waiver request. While that information may not be influential in terms of the waiver request, we believe that information to be relevant and would like to capture those points for the record that will accompany SPP’s recommendation on the waiver request.

Please provide the above requested data no later than March 16th to allow SPP to review the data provided and to formulate a report to the CAWG/RTWG for recommendation to the MOPC in accordance with the tariff requirements.

Thank you.

Sincerely,

John E. Mills, P.E.
Manager, Tariff Studies
Southwest Power Pool
cc: C. Holman
    T. Littleton
    H. Dawson
    Les Dillahunty
    Pat Bourne
    Jay Caspary
Lighting the Past…Powering the future
March 13, 2007

Mr. John Mills
Southwest Power Pool
415 N, McKinley, 140 Plaza West
Little Rock, AR  72205

Subject: Request for waiver per Attachment J of the SPP OATT for OASIS Request #1159596

Dear John,

OMPA is responding to your March 2, 2007, request for additional information in support of reservation #1159596. This reservation request was submitted under SPP-2006-AG3-AFS-1. OMPA has subsequently continued this reservation into AFS-2 and most recently into AFS-3.

Reservation #1159596 is for the necessary transmission capacity to provide for OMPA’s ownership share of the Turk Plant to be located in Hempstead County, Arkansas. The reservation request was for 41MW with a Point of Receipt (“POR”) of CSWS and a Point of Delivery (“POD”) of CSWS. The initial term of this transmission request is 20 years.

Available Base Plan Funding for OMPA’s reservation is $7,380,000. Per 2006-AG3-AFS-1, the Engineering and Construction Cost Allocated to OMPA for this reservation is estimated at $8,597,956. The result is that the cost for OMPA’s portion of the necessary upgrades for the Turk plant is $1,217,956 greater than the allowable Base Plan Funding. It is for the additional cost, beyond the $7,380,000, that OMPA is seeking waiver.

Subsequent to the initial Waiver Request, SPP-2006-AG3-AFS-2 was issued by SPP. Based on this study, the Engineering and Construction Cost allocated to OMPA for this reservation has risen to $28,376,454. It would appear that OMPA is expected to pick up a significant portion of the cost of one leg of the “X Plan” under the reservation. Based on discussions with SPP staff, the AFS-2 costs are incorrect and will be significantly changed in AFS-3 (see discussion below). It is based on this feedback from the SPP staff that OMPA chose to remain in the study through AFS-3.

The following discussions attempt to respond to the individual questions/requests for additional data in your March 2, 2007 letter.
Benefit to SPP of OMPA’s Long Term Transmission Service Request –

Several points in your letter request information from OMPA as to how OMPA’s long term transmission service request provides benefit to SPP. This was addressed in the initial waiver request, however, because of the importance of this issue to the overall waiver request we will address it again in greater detail.

OMPA’s transmission service request, reservation #1159596 is for a period of 20 years. This service request is for 41 MW of base load coal fired generation. The Turk facility will have a very high capacity factor resulting in efficient use of the transmission system.¹

OMPA’s plans to meet a significant portion of its future load requirements by acquiring a portion of the Turk power plant, supported by an initial 20-year transmission reservation. A reservation of this length should allow SPP to efficiently plan the transmission system for the region’s long term needs and will result in significant savings to SPP.

For instance, OMPA is committing to a single 20-year DNR reservation for the Turk plant. On the other hand, rather than identify one long-term source for the power, OMPA could have sought a different power supply arrangement having only a five-year duration. This five-year option would have been eligible for the same level of Base Plan Funding as the Turk plant reservation. OMPA could have sought subsequent five-year reservations. The result of this approach would look something like the following:

<table>
<thead>
<tr>
<th>Year</th>
<th>Reservation, MW</th>
<th>Potential Base Plan Funding</th>
</tr>
</thead>
<tbody>
<tr>
<td>Year 0</td>
<td>41</td>
<td>$7,380,000</td>
</tr>
<tr>
<td>Year 5</td>
<td>41</td>
<td>$7,380,000</td>
</tr>
<tr>
<td>Year 10</td>
<td>41</td>
<td>$7,380,000</td>
</tr>
<tr>
<td>Year 15</td>
<td>41</td>
<td>$7,380,000</td>
</tr>
<tr>
<td>Year 20</td>
<td>41</td>
<td>$7,380,000²</td>
</tr>
<tr>
<td>Total Potential Base Plan Funding</td>
<td>$36,900,000</td>
<td></td>
</tr>
</tbody>
</table>

Thus, SPP’s total Base Plan Funding exposure for OMPA’s multi 5-year contract 20-year, 41 MW reservations, could approach $36,900,000.

The single OMPA Turk Plant reservation, based on AFS-1 costs, would, if approved, limit SPP’s total exposure to $8,597,956, which consists of OMPA’s eligible Base Plan Funding amount of $7,380,000, plus the waiver amount estimated $1,217,956.³ The potential savings to SPP over the 20-years cold approach $28,000,000.

¹ AEP estimates Equivalent Availability Factor for the plant of 87.6%, see, Arkansas Public Service Commission, Docket No. 06-154-U, 19 at 29, Testimony of James A. Kobyra, P.E.
² This table presents the dollar values included in the original waiver request to SPP. The last period would actually go beyond the 20-year reservation request.
³ OMPA is seeking a waiver for the entire amount in excess of the allowable base plan funding and not for any specific dollar amount. The dollars in this analysis are for comparison purposes only.
Length of Transmission Service Request –
OMPA’s reservation #1159596 was for a period of 20 years. OMPA selected 20 years for this reservation request because it is consistent with the term of purchase power contracts offered for similar capacity across the SPP footprint. In addition, the reservation term is consistent with requests submitted by AEP, #1162214; AECC, #1161209; NTEC, 1161974. Given that the life of the project will be at least 30 years (see discussion below) OMPA would not have a problem with a service request for 30-years or longer.

35 Year Plant Life –
On September 18, 2006 OMPA notified SWEPCO of our intention to participate in the Hempstead County Pulverized Coal Facility.\(^4\) The project name has subsequently been changed to the Turk project. OMPA is in the final stages of negotiating an ownership agreement with SWEPCO for a 6.667% (nominal 40 MW) share of the project. OMPA’s share will be a life-of-unit ownership share and will not terminate at any specific time.

While there has been reference to the economic life of the plant being 30 years, OMPA expects that this state of the art plant will have an operating life greater than 35 years,\(^5\) considering that the average age of a coal fired generator in the U.S. is approximately 42 years.\(^6\)

Projected Fuel Mix –
OMPA has previously provided SPP with long-range load and resource projections as part of the CDR process. Based on the data included in the most recent CDR, adjusted for changes in OMPA’s generation mix, OMPA projects the following fuel mix. The 2010 mix is prior to the commercial operation of the Turk Plant and the 2012 subsequent the commercial operation of the Red Rock Plant. The 2014 mix is after various OMPA other resources terminate.

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>2010</th>
<th>2012</th>
<th>2014</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>4%</td>
<td>1%</td>
<td>4%</td>
</tr>
<tr>
<td>Coal/Lignite</td>
<td>63%</td>
<td>74%</td>
<td>65%</td>
</tr>
<tr>
<td>Hydro</td>
<td>12%</td>
<td>12%</td>
<td>12%</td>
</tr>
<tr>
<td>High Efficiency Gas</td>
<td>16%</td>
<td>7%</td>
<td>14%</td>
</tr>
<tr>
<td>Wind</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
</tr>
<tr>
<td>Unknown</td>
<td>0%</td>
<td>0%</td>
<td>0%</td>
</tr>
</tbody>
</table>

The increased reliance on coal-fired generation produced by OMPA’s long-term commitment to the Turk Project will yield benefits not only to OMPA, but also to other ratepayers in the region. OMPA will likely bid this unit into the imbalance market, lowering LIPS to ratepayers in the SPP region. This unit will also contribute to reducing regional dependence on gas, and increase the hours when low cost coal, rather than gas, is on the margin in the SPP region, as well as contributing to resource adequacy. Because the plant is intended to operate on a baseload basis, the regional benefits of this low cost energy should be expected to flow around the clock.

\(^4\) See attached letter from Roland Dawson to Venita McClellon-Allen.
\(^5\) A significant portion of OMPA’s bonds for this project will mature as late as 35 years after the project becomes commercial, see Official Statement at 5.
SPP-2006-AG3-AFS-2 –
SPP has asked OMPA to comment on the waiver request for OASIS reservation #1159596 in light of SPP-2006-AG3-AFS-2. OMPA is hard pressed to comment on the OASIS reservation as it is our understanding that the results of AFS-2 are incorrect and problematic in relation to this reservation. For example, in AFS-1, the $31,000,000 cost of the Caney Creek upgrade was spread amongst 27 reservation requests. In AFS-2 the $31,000,000 cost of the Caney Creek upgrade is spread amongst only two reservations, AEP’s reservation #1162223 and the OMPA reservation #1159596. Specific need for this project to meet OMPA’s Turk requirements is highly questionable and should be further studies by SPP staff.

Discussions with SPP staff indicate that the $31,000,000 proposed solution to the transmission availability in Southeast Oklahoma, and in particular the Caney Creek upgrade, is neither the best nor most economical approach to the problem.

Furthermore, the proposed Caney Creek upgrade and several alternatives such as the option of supporting the Caney Creek substation from the proposed Hugo/Sunnyside 345 kV line are high level regional improvements which would be of region wide benefit, rather than simply benefiting OMPA and AEP. As of yet, OMPA has not seen a study that simply addresses the minimum improvements to support ONLY OMPA’s request and not an aggregated basis.

OMPA does not believe it should carry the brunt of the 345 kV improvements, but remains in support of improvements to the SPP system at the highest levels possible. The more robust the transmission system better reliability and lower cost will accrue to all SPP members. SPP has just addressed this very concept when the SPP Board, at their January 30, 2007 meeting, approved a waiver request for a peaking plant, which approval resulted in covering the cost of improvements to the 345 kV system (vs. lower cost improvements to the 138 kV system) through base plan funding, rather than assigning it to the individual entity. Consistent with that precedent, the cost of the high level improvements related to OMPA’s reservation should also be covered with base plan funding.

Peaking or Intermediate Generation –
OMPA did not intend to indicate that OMPA’s waiver request would provide ANY value for peaking and intermediate generation as suggested in your letter. OMPA’s statement was:

OMPA’s waiver request provides greater regional value than previous waiver requests that have been for peaking or intermittent generation, and does so at lower cost [per MW] to other SPP ratepayers. OMPA’s waiver request amounts to approximately $29,706/MW [for a base load plant], while recent waiver requests pertaining to peaking generation have required roll-in of an additional $63,504/MW.

Waiver Request at 2.
OMPA simply was indicating that waiver request for reservation #1159596 was for a base load plant at an estimated additional cost, above Base Plan Funding, of $29,706/MW as compared to a recently approved waiver request which was for a peaking plant at an estimated cost, above Base Plan Funding, of $63,504/MW.

Comparability –
Based on the results of AFS-1 and AFS-2, OMPA is concerned with comparability. OMPA submitted request #1159596 for its 41 MW share of the output of the Turk Plant. This reservation originates and delivers in the CSWS system. In AFS-2, the total E&C cost for OMPA’s reservation request is $234,225,273 with OMPA’s allocated share being $28,376,454. AEP submitted reservation #1162216 for their 455 MW share of the Turk Plant. The AEP reservation also originates and delivers in the CSWS system. The total E&C cost for the AEP reservation request is $115,000,000 with AEP’s allocated share being $65,804,529.

<table>
<thead>
<tr>
<th>AFS-1</th>
<th>AEP</th>
<th>OMPA</th>
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<tbody>
<tr>
<td>Reservation</td>
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<td>1159596</td>
</tr>
<tr>
<td>MW</td>
<td>455</td>
<td>41</td>
</tr>
<tr>
<td>POR</td>
<td>CSWS</td>
<td>CSWS</td>
</tr>
<tr>
<td>POD</td>
<td>CSWS</td>
<td>CSWS</td>
</tr>
<tr>
<td>Total E&amp;C Cost</td>
<td>$558,681,418</td>
<td>$591,576,418</td>
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<tr>
<td>Allocated E&amp;C Cost</td>
<td>$69,818,962</td>
<td>$8,603,598</td>
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<tr>
<td>Available Base Plan Funding</td>
<td>$81,900,000</td>
<td>$7,380,000</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>AFS-2</th>
<th>AEP</th>
<th>OMPA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservation</td>
<td>1162214</td>
<td>1159596</td>
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<tr>
<td>MW</td>
<td>455</td>
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<td>POR</td>
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<td>Total E&amp;C Cost</td>
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<td>$234,225,273</td>
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<tr>
<td>Allocated E&amp;C Cost</td>
<td>$65,804,529</td>
<td>$28,376,454</td>
</tr>
<tr>
<td>Available Base Plan Funding</td>
<td>$81,900,000</td>
<td>$7,380,000</td>
</tr>
</tbody>
</table>

It seems peculiar to OMPA that the AFS-2 E&C costs for OMPA’s reservation (which is less than 10% of AEP’s reservation) would be double the E&C cost for the AEP reservation. AEP’s reservation is over 10 times larger than the OMPA reservation and it originates at exactly the same location as OMPA’s reservation. AEP’s reservation is delivered into the CSWS system, as is OMPA’s reservation. OMPA would concede that there may be a difference in the actual sink locations, however, surely there is not such a huge difference in the final sink location/flow amounts for at least a portion of the AEP reservation (for instance 10% of the AEP reservation or 45 MW) that a portion of the

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7 Based on AFS-1 where the cost in excess of Base Plan Funding was estimated at $1,217,956.
E&C cost allocated to OMPA would not likewise be shared with AEP. This result calls into question the credibility of the modeling.

Should you have any additional questions on OMPA’s waiver request please do not hesitate to contact me.

Sincerely,

Robin J. Morecroft, P.E.
Director of Engineering Services
DESIGN PRINCIPLES FOR A BALANCED PORTFOLIO OF ECONOMIC TRANSMISSION UPGRADE PROJECTS

GOAL: The goal for designing a portfolio of economic transmission upgrade projects is to achieve a balance of benefits throughout the SPP footprint. Generally this means a portfolio distribution of benefits similar to the distribution of loads within the SPP footprint.

APPLICATION: In order to achieve the goal of a balanced portfolio of projects, it is likely that projects in certain sub-regions that have lower benefit to costs ratios will be included in the portfolio, while projects in other sub-regions that have higher benefit to costs ratios will be excluded from the portfolio. In this regard, the RSC seeks discussion on the following questions.

QUESTIONS FOR DISCUSSION:
1. Is the “substitution” of lower benefit to cost ratio projects for higher benefit to cost ratio projects an acceptable process to follow in order to achieve a balanced portfolio?
   a. If not, what implications does this have for cost allocations of an unbalanced portfolio of economic upgrade projects?
   b. If so, should a lower limit to the benefit to cost ratio be placed on individual projects for inclusion in the balanced portfolio, and if so, what should that lower limit be? For example, should a project whose costs exceed its benefits be included in the portfolio?

2. Should an overall lower limit on the benefit to cost ratio be placed on the portfolio of projects?
   a. Is setting a lower limit on individual projects for inclusion in the portfolio sufficient to ensure that an acceptable benefit to cost ratio will be achieved by the design of the overall portfolio?
   b. If an overall lower limit is needed, what should that limit be?

EXAMPLE: The following example is meant to help illustrate the above questions. Suppose a set of projects SPP is considering have the following benefit to cost ratios:

<table>
<thead>
<tr>
<th>Project</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>11</th>
<th>12</th>
<th>Avg</th>
</tr>
</thead>
<tbody>
<tr>
<td>B/C</td>
<td>3.00</td>
<td>2.75</td>
<td>2.50</td>
<td>2.25</td>
<td>2.00</td>
<td>1.75</td>
<td>1.50</td>
<td>1.25</td>
<td>1.15</td>
<td>1.10</td>
<td>1.05</td>
<td>1.00</td>
<td>1.78</td>
</tr>
</tbody>
</table>

In order to balance the benefits of this portfolio of projects SPP removes project 2 and replaces it with a project that has a significantly lower benefit to cost ratio.

<table>
<thead>
<tr>
<th>Project</th>
<th>1</th>
<th>2*</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>11</th>
<th>12</th>
<th>Avg</th>
</tr>
</thead>
<tbody>
<tr>
<td>B/C</td>
<td>3.00</td>
<td>0.85</td>
<td>2.50</td>
<td>2.25</td>
<td>2.00</td>
<td>1.75</td>
<td>1.50</td>
<td>1.25</td>
<td>1.15</td>
<td>1.10</td>
<td>1.05</td>
<td>1.00</td>
<td>1.62</td>
</tr>
</tbody>
</table>

Question 1 asks whether or not this type of “substitution” is acceptable, and whether or not any lower limit should be placed on the benefit to cost ratio of the projects included in the portfolio. With a benefit to cost ratio of 0.85, the expected costs of the substitute project exceeds its expected benefits. Thus, an additional question is whether or not projects whose costs exceed their benefits should be included.

Question 2 deals with whether or not there should be an overall lower limit placed on the benefit to cost ratio of the portfolio. Under question 2.a, notice that if you place a lower limit of 1.0 on individual projects, the portfolio will have a benefit to cost ratio that is higher than 1.0 because most of the projects in the portfolio will have benefits in excess of their costs.
Design Principles for Balanced Portfolio of Economic Transmission Upgrade Projects

- Goal: The design a balanced portfolio of economic projects for SPP Region.
- Design Principles:
  Balanced Portfolio vs. Optimal Portfolio.
### Principles for Designing Portfolios

<table>
<thead>
<tr>
<th>Project Number</th>
<th>Project Cost</th>
<th>Dispatch Savings</th>
<th>Benefit to Cost Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$23.15</td>
<td>$69.45</td>
<td>3.00</td>
</tr>
<tr>
<td>2</td>
<td>$17.23</td>
<td>$47.38</td>
<td>2.75</td>
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<tr>
<td>3</td>
<td>$25.63</td>
<td>$64.08</td>
<td>2.50</td>
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<tr>
<td>4</td>
<td>$17.45</td>
<td>$39.26</td>
<td>2.25</td>
</tr>
<tr>
<td>5</td>
<td>$16.76</td>
<td>$33.52</td>
<td>2.00</td>
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<tr>
<td>6</td>
<td>$19.32</td>
<td>$32.06</td>
<td>1.75</td>
</tr>
<tr>
<td>7</td>
<td>$18.75</td>
<td>$58.13</td>
<td>1.50</td>
</tr>
<tr>
<td>8</td>
<td>$17.24</td>
<td>$21.55</td>
<td>1.25</td>
</tr>
<tr>
<td>9</td>
<td>$12.63</td>
<td>$14.52</td>
<td>1.15</td>
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<td>1.10</td>
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<tr>
<td>11</td>
<td>$10.54</td>
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<tr>
<td>12</td>
<td>$22.50</td>
<td>$22.50</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>$252.48</strong></td>
<td><strong>$449.02</strong></td>
<td>1.78</td>
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</table>

### "Optimal" Portfolio

<table>
<thead>
<tr>
<th>Project Number</th>
<th>Project Cost</th>
<th>Dispatch Savings</th>
<th>Benefit to Cost Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$23.15</td>
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<tr>
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<td>$64.08</td>
<td>2.50</td>
</tr>
<tr>
<td>4</td>
<td>$17.45</td>
<td>$39.26</td>
<td>2.25</td>
</tr>
<tr>
<td>5</td>
<td>$16.76</td>
<td>$33.52</td>
<td>2.00</td>
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<tr>
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<td>$19.32</td>
<td>$32.06</td>
<td>1.75</td>
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<tr>
<td>7</td>
<td>$18.75</td>
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<td>$21.55</td>
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<td>1.10</td>
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<tr>
<td>11</td>
<td>$10.54</td>
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<td>1.06</td>
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<tr>
<td>12</td>
<td>$22.50</td>
<td>$22.50</td>
<td>1.00</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$260.46</strong></td>
<td><strong>$423.07</strong></td>
<td>1.62</td>
</tr>
</tbody>
</table>

### "Balanced" Portfolio

Resulting Portfolio will have B/C > 1

<table>
<thead>
<tr>
<th>Project Number</th>
<th>Project Cost</th>
<th>Dispatch Savings</th>
<th>Benefit to Cost Ratio</th>
</tr>
</thead>
<tbody>
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<td><strong>Total</strong></td>
<td><strong>$260.46</strong></td>
<td><strong>$423.07</strong></td>
<td>1.62</td>
</tr>
</tbody>
</table>

### Design Principles Questions

1. To achieve a balanced portfolio is it acceptable to substitute a lower benefit to cost ratio project for a higher one?
   a. NO – implications for cost allocation?
   b. YES – lower limit on individual projects?

2. Should an overall lower limit on the benefit to cost ratio be placed on the portfolio?
   a. Lower limit on individual projects sufficient?
   b. If not, what should be lower limit for portfolio?
All,

In an earlier RSC teleconference Commissioner Gaw raised a question concerning SPP’s administrative role for the RSC based upon his recollection of FERC Orders in two other cases. In response to Commissioner Gaw’s inquiry, SPP staff asked its Missouri Counsel, David Linton, to review the cases in question and to provide an analysis. Attached are the related documents.

Additionally, attached are three separately generated attachments entitled SPP Revised Bylaws, Proposed Revisions Cover and Travel Policy. These attachments contain possible edits to the RSC Bylaws and Travel Policy to address changes that have been suggested.

Les
Memorandum

To: Les Dillahunty
From: David C. Linton
Date: March 12, 2007
Re: Analysis of SPP/RSC Travel Policy

The purpose of this memorandum is to provide a response to the question of the propriety of the SPP’s Travel Policy and SPP’s reimbursement of RSC travel expenses. This analysis considers the propriety of the Travel Policy in light of two Federal Energy Regulatory Commission (“FERC” or “Commission”) Orders: New England Governors, 112 FERC ¶ 61,049 (2005) and PJM Interconnection, L.L.C., 113 FERC ¶ 61,292 (2005).

In the New England Governors case, ISO New England filed pursuant to section 205 of the Federal Power Act (“FPA”) revised tariff sheets to collect its administrative costs. As part of that filing, it included a proposed Schedule 5, a “placeholder,” to account for the possibility that an RSC (“NESCOE”) would be formed in New England and would seek to justify and recover its costs through the tariff structure. The Commission rejected the proposed schedule as being premature. Subsequently, the Commission provided additional clarification. It is that subsequent order that is the subject of this inquiry.

In response to a claim that such cost recovery was unprecedented, the Commission cited both SPP’s and MISO’s RSC budgeting and cost recovery processes. FERC observed that, “If New England participants agree to a similar mechanism, then parties would have input as to NESCOE’s budget, and ISO-NE’s Board would have final approval. Such a process could relieve concerns regarding ISO-NE’s independence and its ability to justify the proposed budget.” New England Governors, P. 39. The Commission denied rehearing and reiterated that approval of the proposed schedule was premature because the stakeholders had not deliberated on the cost recovery mechanism.

In the PJM Interconnection case, PJM filed an amendment to its OATT to provide a mechanism for funding the Organization of PJM States, Inc. (OPSI). In its order, the subject of this analysis, the Commission accepted the filing subject to some limited revisions. In its discussion of the tariff, it concluded that the costs of OPSI were legitimate business expenses of PJM that benefited the entire market. One key consideration for the FERC was the ability of the stakeholders to evaluate the prudence of the proposed expenditures through the process. Generally, it found that the process would permit stakeholders adequate opportunity to object. However, it did find that the mechanism in the tariff amendment provided too little time for stakeholders to review the proposed budget. As a result, it directed PJM to amend its tariff to change the deadline for submission of the OPSI budget from August 1 to June 1.
The most significant point of comparison between these two cases and SPP’s RSC cost recovery mechanism is a point of distinction. Whereas the *New England Governors* and *PJM Interconnection* cases involved section 205 proceedings before FERC to establish funding processes, SPP has an accepted RSC funding process. See *Southwest Power Pool*, 108 FERC ¶ 61,003 (2004). In that case, the Commission accepted Section 7.2 of SPP’s bylaw as SPP’s RSC funding mechanism. Section 7.2 of SPP’s bylaws state in relevant part, “SPP will fund the costs of the RSC pursuant to an annual budget developed by the RSC and submitted to SPP as part of its budgeting process, which budget must ultimately be approved by the Board of Directors.” Obviously, SPP must follow its budgeting procedures. However, SPP’s existing tariff is subject to section 206 of the FPA rather than section 205.

There is one other matter that is worthy of note from the *New England Governors* and *PJM Interconnection* cases. The Commission’s primary concern in both cases was the stakeholders’ opportunity to review budget proposals. Its Order on Rehearing in the *Southwest Power Pool* case is certainly consistent with that concern. In that Order, it granted TDU Intervenors’ rehearing request and directed SPP to make an annual informational filing of its operating budget and to consult with stakeholders prior to filing. See *Southwest Power Pool*, 109 FERC ¶ 61,010 (2004), at P. 98. As I read the Travel Policy, it is policy guidance used in the implementation of the budgeting process. As such, it will give stakeholders additional guidance in their assessment of budget proposals, something akin to business practices as they relate to the OATT. In complying with its budgeting process, SPP should be free to assume that its tariff procedures are just and reasonable in protecting the interests of its stakeholders.
PJM Interconnection, L.L.C. Docket Nos. ER06-78-000 and ER06-78-001

ORDER ON FUNDING MECHANISM FOR ORGANIZATION OF PJM STATES, INC.

(Issued December 20, 2005)

1. On October 28, 2005 as amended November 3, 2005, PJM Interconnection, L.L.C. (PJM) filed an amendment to its Open Access Transmission Tariff (OATT)\(^1\) to provide a mechanism for funding the Organization of PJM States, Inc. (OPSI), the regional state committee (RSC) in the PJM region comprised of the regulatory commissions within PJM's footprint formed to interact with PJM and its members.\(^2\) We will accept the proposed amendment to the PJM OATT effective January 1, 2006 subject to the revisions discussed herein.

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\(^2\) OPSI's membership includes: Delaware Public Service Commission; District of Columbia Public Service Commission; Illinois Commerce Commission; Indiana Utility Regulatory Commission; Kentucky Public Service Commission; Maryland Public Service Commission; Michigan Public Service Commission; New Jersey Board of Public Utilities; North Carolina Public Service Commission; Public Utilities Commission of Ohio; Pennsylvania Public Utility Commission; Tennessee Regulatory Authority; Virginia State Corporation Commission; and West Virginia Public Service Commission.
I. Background

2. PJM states that the Commission has recognized the important role of the states in the formation, governance, and development of regional transmission organizations (RTOs) in its key orders and policy statements. PJM explains that where, as here, an RTO covers a footprint encompassing a multi-state region, the Commission has sought to create new venues that would allow states to coordinate their regulatory policies on matters subject to their jurisdiction and provide opportunities to form a common state perspective on issues related to wholesale power markets and interstate transmission. PJM states that specifically the Commission has proposed that state commissions form RSCs that would develop (in whatever form that suited them) formal decision-making structures and procedures.

3. PJM asserts that, in order to facilitate this objective, the Commission has invited RTOs to seek reimbursement of states’ reasonable expenses in the formation and support of such bodies. PJM states that, although the Commission has stopped short of requiring the formation of RSCs, as it initially contemplated, there is every indication that the Commission continues to favor this approach. PJM states that this concept of collective regional state deliberative processes also has the support of Congress, which has included, for example, a legislative mandate in the Energy Policy Act of 2005 to convene joint state boards on a regional basis in order to study and develop recommendations regarding the use of economic dispatch in various regions of the country.

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4 PJM states that although the Commission has terminated the Standard Market Design Notice Of Proposed Rulemaking proceeding, citing the continued voluntary formation of RTOs in regions such as the PJM region and the Commission’s intent to proceed with reform of the Pro Forma OATT, it has never indicated any intention to rescind any policy or recommendation in that proceeding intended to promote or otherwise facilitate the development of RTOs in a region where their growth and development has continued unabated. See Remedying Undue Discrimination through Open Acess Transmission Service and Standard Electricity Market Design, 112 FERC ¶ 61,073 at P 6 (2005). PJM also states that the Commission recently has cited with approval Midwest Independent Transmission System Operator, Inc.’s and Southwest Power Pool’s practice of including their respective RSC’s cost in their administrative budgets. See New England Governors, 112 FERC ¶ 61,049 P 39 (2005).

II. Role of the Organization of PJM States, Inc.

4. PJM states that the fourteen regulatory commissions within the footprint of PJM have organized OPSI as a non-stock corporation in Delaware. PJM also states that OPSI’s stated purpose is to “provide a means for the PJM States to act in concert, when deemed to be in the common interest…” PJM explains that on June 1, 2005, PJM and OPSI entered into a Memorandum of Understanding (MOU), in which they agreed that OPSI would function as a liaison group, meeting with PJM at least annually; collect information (which PJM agrees either to provide or explain its basis for withholding); monitor markets and events; consider PJM-related proposals affecting reliability, safety, facility siting and electricity prices; and submit proposals.

5. PJM contends that OPSI presents an opportunity to mitigate the regulatory costs, uncertainties and delays that could result from the balkanization of state regulatory participation and review of wholesale electricity market issues in the PJM region over fourteen different jurisdictions. PJM notes that the Commission has recognized state authority affecting such matters as transmission and capacity planning is crucial to the development of efficient energy markets. PJM states that, to the extent that OPSI can help the states appreciate their mutual, regional interests, it will serve to curb parochialism and foster a cooperative approach to planning on a regional basis. PJM also states that, although in time OPSI could evolve into a regional layer of coordinated governance over a discrete scope of electricity issues, the present framework is relatively modest.

6. PJM explains that currently OPSI is run entirely by persons with many other responsibilities. PJM believes that OPSI needs a small support staff in order to avoid imposing an excessive burden on state officials, to provide a small cadre of neutral intermediaries among the state members, and to allow for some institutional continuity. PJM asserts that the funding requested for OPSI primarily serves to support this staff. PJM contends that, in order to preserve the regional character of OPSI as an organization, it is appropriate that the region fund it rather than the states. PJM states that an obvious and administratively convenient method for the “region” to fund OPSI is for the RTO to collect the costs of the RSC, and the Commission already has anticipated and solicited this approach. PJM also states that it intends to facilitate the development of an RSC that will play a constructive role in its region, and has developed this proposal in cooperation with OPSI.

III. Proposed Rate Schedule 9-OPSI

7. After consultations with its stakeholders and OPSI, PJM proposes to collect OPSI’s annual budget through a dedicated formula rate. Proposed Schedule 9-OPSI provides that each year OPSI will develop its budget for the following calendar year and submit it to the PJM Finance Committee for comment. No later than October 31 of each year, PJM will inform the Commission of OPSI’s final budget and post the resulting OPSI Funding Rate on its internet site. OPSI’s initial budget is $425,000. PJM explains that in order to promote fiscal restraint and rate certainty, Schedule 9-OPSI provides that any budget submitted for a calendar year that includes an increase in excess of fifteen percent of the budget on file for the current calendar year will require the Commission’s approval by means of a subsequent section 205 filing by PJM.

8. PJM proposes to charge each user of transmission provided by PJM each month a charge equal to the OPSI Funding Rate (OFR) times the total quantity in MWhs of energy delivered during such month by such user as a transmission customer under its tariff. PJM states that under proposed Schedule 9-OPSI the OFR is based on (i) an estimate of energy deliveries expected in the following calendar year and (ii) a true-up to account for actual under-or over-recovery of OPSI’s budget during the prior calendar year. PJM will state separately the charge associated with Schedule 9-OPSI on a customer’s bill, which will reflect the application of the OPSI Funding Rate to every megawatt-hour of energy delivered under the tariff.

9. PJM asserts that this approach balances the need for transparency and a reasonable degree of oversight over OPSI’s budget against the need to preserve the independence of the organization from outside control over its budgetary purse strings or from similar conflicts of interest. PJM explains that the PJM Finance Committee has an opportunity to advise OPSI in preparing its budget, but does not approve it. PJM states that the review process will give stakeholders an adequate opportunity to complain about anything they perceive as excessive in PJM’s annual informational filings. Schedule 9-OPSI provides that PJM will file with the Commission under section 205 for review any future annual OPSI budget seeking an increase of more than fifteen percent. PJM asserts that stating the charge associated with OPSI’s activities separately will provide additional transparency with respect to OPSI’s costs. PJM contends that a more elaborate review process is unnecessary and wasteful given the relatively low level of funding that OPSI requires.

10. PJM states that it is also appropriate that Rate Schedule 9-OPSI be stated separately from PJM’s rate for administrative services. PJM asserts that OPSI is totally independent of PJM. PJM argues that OPSI’s status is analogous to that of the Mid-Atlantic Area Council (MAAC), an organization that PJM collects funding for through a separate charge calculated pursuant to Schedule 10. PJM contends that the Commission to date has not had jurisdiction over these regional reliability council costs yet the RTOs
have been used as a vehicle for collecting them pursuant to the Commission-approved tariff. PJM contends that this precedent is even more compelling when applied to OPSI. PJM also states that by keeping apart the mechanisms used to fund wholly separate organizations with separate missions, PJM is more able to keep its financial affairs transparent to its stakeholders and the public it ultimately serves. PJM requests that Rate Schedule 9-OPSI become effective January 1, 2006.

11. PJM explains that it prefers not to include in its general budget costs that it does not manage. PJM asserts that this is especially the case considering PJM’s request to move from a formula rate to a stated rate for those charges within its control.\(^7\) PJM states it would be counterproductive, at a time of focus on fiscal control, for the RTO to have to absorb costs of entities outside of its control within a fixed-rate proposal designed to drive internal efficiencies and cost reductions. PJM states that for the reasons explained above, OPSI’s budget should not be subject to PJM’s discretionary authority. PJM contends that these types of costs should be isolated from general administrative costs so that PJM and the Commission can better evaluate PJM’s progress in improving its cost management.

12. PJM states that it is aware that the Commission has questioned the necessity for a similar approach for collecting the RSC costs proposed for New England’s RSC. PJM also states that most of the reasons provided above would also support ISO New England’s approach.\(^8\) However, PJM asserts that OPSI’s proposed budget is smaller and includes a mechanism providing stakeholder participation and input, encouraging fiscal restraint, and PJM’s stakeholders overwhelmingly welcome OPSI’s creation, purpose and participation in RTO affairs. PJM states that on September 29, 2005, the Members Committee endorsed the OPSI rate schedule with approximately 85 percent of the voting membership in favor.\(^9\) PJM notes that the PJM Finance Committee recommended that the Members Committee approve the proposal.

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\(^7\) See PJM Interconnection, L.L.C., Docket No. ER05-1181-000.


\(^9\) PJM states that the rate schedule OPSI proposed to the PJM membership did not provide for the 15 percent escalation limit included in this filing. PJM states that OPSI elected to include this limitation in the instant rate schedule following PJM’s September 29, 2005, Members Committee meeting in order to provide PJM and its members additional comfort that its costs would be kept in check.
IV. Notice of Filing


14. Timely motions to intervene and notices of intervention were filed by the Pennsylvania Public Utility Commission, Public Service Commission of Maryland, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company. Timely motions to intervene and protests were filed by American Municipal Power – Ohio, Inc. (AMP-Ohio) and PSEG Energy Resources & Trade LLC (PSEG). A timely notice of intervention and comments were filed by the Kentucky Public Service Commission (Kentucky PSC). Timely motions to intervene and comments were filed by the OPSI, Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (Constellation). OPSI filed an answer to the comments and protests on December 5, 2005.

V. Protests and Comments

A. Funding

15. AMP-Ohio and PSEG oppose the funding mechanism proposed to support OPSI. Additionally, Constellation, AMP-Ohio and PSEG raise concerns about the future costs of OPSI. Constellation does not object to the initial proposed budget for OPSI, it is concerned that given the stakeholder as well as Commission efforts to reduce the costs associated with the RTOs, it is inappropriate to permit OPSI to increase its budget by up to 15 percent annually, with no dollar cap in the aggregate. PSEG and Constellation argue that the budget increases should be reviewed by the Commission prior to becoming effective so that parties have the opportunity to comment on the prudence of the costs. Alternatively, Constellation argues that the Commission should require a lower threshold of increase, such as three to five percent, concomitant with an aggregate cap of no more than a $45,000 increase over the initial filed budget that would trigger a requirement to file with the Commission for acceptance.

16. PSEG contends that the OPSI funding mechanism includes a provision allowing OPSI to increase its annual budget by up to 15 percent year without any need for Commission review. PSEG contends that as a general matter, authorization of an unrestricted annual growth rate of 15 percent for an organization to be supported through RTO funding would be excessive. PSEG asserts that if OPSI is funded based on PJM transmission usage, the Commission should approve budget increases. PSEG contends that, at most, increases in levels up to the rate of inflation could be permitted without the
need for Commission review and that budget increases in excess of the rate of inflation should be filed with the Commission.

17. AMP-Ohio contends that this is just the latest in a series of actions to pancake additional costs on the supposedly deep pockets of load serving entities (LSEs). AMP-Ohio asserts that the fact that the cost is low (initially) does not justify its automatic imposition on load. AMP-Ohio states that there are fourteen state regulatory commissions participating in OPSI, and if the budgeted $425,000 expense were paid by them, where the expense belongs in the first instance, the average annual cost for each commission would be only $30,357. AMP-Ohio argues that more importantly, as we have seen with runaway RTO costs in general, when the entity that incurs the costs is free to shift them elsewhere for payment with little or no oversight, those costs have a habit of escalating well beyond a reasonable level.

18. Additionally, AMP-Ohio and PSEG protest the funding of OPSI, the members of which are state regulatory commissions, through transmission costs. AMP-Ohio argues that wholesale purchasers of PJM transmission should not be required to pay for the cost of state retail commission participation in the PJM stakeholder process. AMP-Ohio asserts that although PJM states that state regulatory authorities affect such areas as transmission and capacity planning, it is not at all clear that their participation in the PJM stakeholder process is related to those functions as opposed to representing “the interests of their constituents.” AMP-Ohio contends that state commissions frequently define their constituents by the scope of their regulatory authority. PSEG contends that the state commissions that OPSI represents are obligated by state law to ensure that the interest of end users (load) have been fully considered.

19. AMP-Ohio asserts that the Commission should reject PJM’s proposal and allow the state commissions to raise the modest necessary revenue under state-mandated procedures. AMP-Ohio explains that those assessed a share of these costs could recover them from retail and wholesale customers as circumstances justify and regulators permit. AMP-Ohio states that should the Commission determine that it is appropriate for PJM to pay the OPSI expenses and to do so through the imposition of a new Schedule 9 charge; the Commission should limit the application of that charge to entities that are subject to the jurisdiction of the state agencies. AMP-Ohio believes that such a limitation will have only a very minor affect on the individual charges.

20. PSEG argues that PJM’s proposal to seek funding constitutes a financing mechanism to benefit a particular interest group at the expense of all the transmission customers of PJM. PSEG contends that no other interest group has been distinguished in the same manner as OPSI for financial assistance. PSEG argues that by facilitating the

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opportunity for state commissions to participate in the PJM stakeholder process through a funding mechanism built on the backs of other PJM stakeholders, and not providing similar funding opportunities to PJM market participants with different viewpoints, the OPSI funding mechanism has the effect, or at least gives the appearance, of allowing OPSI to exercise undue influence over the PJM stakeholder process. PSEG asserts that at a minimum, elevating the status of OPSI in this manner suggests that the views of OPSI as a stakeholder are more important and are entitled to more weight than those of other PJM market participants.

B. State Commissions

21. The Kentucky PSC states that the Commission has encouraged the formation of Regional State Committees such as OPSI and has previously approved tariffs to fund them. The Kentucky PSC states that as a member of the Organization of MISO States (OMS) it is familiar with how it is funded and what it does, and, based on that experience, the Kentucky PSC urges the Commission to approve the proposed tariff revision for OPSI. Other state commissions have filed interventions.

C. Commission Authority

22. PSEG argues that the proposal to fund OPSI is inconsistent with provisions of state law regarding the funding of state regulatory agencies, and the funding of state regulatory agencies and the manner in which the agencies spend their budgets are matters of state law. Thus, PSEG argues that the Commission will overstep its bounds if, in effect, it approves state agency spending for activities that the state agencies themselves have apparently not been funded to perform by the state legislatures. PSEG asserts that if, on the other hand, the respective state governments believe that the activities contemplated by OPSI are necessary for the commissions to carry out their responsibilities, the state governments can and should rely on existing mechanisms provided in the statutes to support them. PSEG states that in the case of the New Jersey Board of Public Utilities (BPU), for example, funding is obtained through an annual assessment on public utilities subject to BPU’s jurisdiction.

23. PSEG asserts that in New Jersey, these charges will ultimately be passed through to end-use customers. PSEG contends that default service, called “basic generation service” (BGS) in New Jersey is procured through a yearly auction. PSEG states that bidders in that auction can be expected to include administrative charges associated with transmission service, such as the OPSI charges, in the bids they make in the auction. PSEG claims that because New Jersey consumers are already paying for the BPU assessment through distribution rates, the payment of additional amounts for BPU activities through the OPSI surcharge will cause amounts paid for state commission activities to exceed the levels intended by the New Jersey legislature. PSEG argues that the situation in New Jersey thus provides a clear example of a case in which the OPSI
funding mechanism undermines legislative intent regarding the budget of the State regulatory agency.

24. AMP-Ohio and PSEG argue that the proposed funding of OPSI would force LSEs to fund views they may oppose. PSEG argues that approval by the Commission of the OPSI funding scheme would constitute an unconstitutional exercise of power over free speech.

D. OPSI’s Comments

25. OPSI states that in addition to the common stake that PJM and the states have in improving regional wholesale market design and operations, the states also have jurisdictional obligations and a longstanding and critical stake in transmission planning, siting and construction. OPSI asserts that all transmission siting is ultimately a local issue. OPSI argues that states necessarily have a direct stake in the regional transmission planning process and how it affects personal and public property, land use and environmental concerns. OPSI explains that it views itself as critical in helping states address regional and local issues in a collaborative fashion. OPSI states that to the extent that this effort is successful, it should yield direct benefits to wholesale market stakeholders, and further the policy objectives of the Commission.

26. OPSI states that in the event of annual escalation of OPSI’s funding of more than 15 percent, the budget will be submitted to the Commission for approval, pursuant to section 205 of the Federal Power Act (FPA). OPSI explains that this provision (Schedule 9-OPSI, section (c)) was drafted in response to issues and suggestions raised by PJM stakeholders during the review of the proposed funding tariff.

27. OPSI contends that it is incorrect to characterize this tariff as providing OPSI with funds with “little or no oversight” as AMP-Ohio suggests. OPSI states that PJM members have and will continue to have a transparent view of OPSI’s funding process, and will have an adequate remedy before the Commission in the event they wish to raise objections to a proposed increase of more than 15 percent per annum.

28. OPSI argues that AMP-Ohio’s suggestion that OPSI funding should be limited to entities subject to the jurisdiction of the state agencies misses the point. OPSI asserts that although its members are drawn from all of the state utility regulatory commissions within the PJM footprint, OPSI does not itself exercise any state jurisdictional powers.

29. OPSI states that federal/state jurisdictional boundaries are complex and there is a clear need for states to work together collectively on wholesale market issues. OPSI cites as a prime example, the timely resolution of transmission planning and siting issues that will involve both the exercise of state and federal jurisdiction and will benefit wholesale
and retail markets and the users of the grid. OPSI believes that the existence and operation of regional state entities such as OPSI helps to provide a forum for regional cooperation.

VI. **Procedural Matters**

30. Pursuant to Rule 214 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2005), the timely unopposed motions to intervene and notices of intervention serve to make the entities that filed them parties to this proceeding.

31. Rule 213(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2)(2005), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept OPSI’s answer because it has provided information that assisted us in our decision-making process.

VII. **Discussion**

32. We will accept PJM’s filing subject to the condition that PJM agrees to revise the filing in certain respects to ensure it is just and reasonable. At the outset, we commend the regulatory commissions within PJM’s footprint for their effort in establishing a RSC, and we agree that the newly formed OPSI has much to offer in formulating policies for the PJM region. OPSI’s funding proposal has broad support among stakeholders. The funding mechanism was recommended for approval by the PJM Finance Committee. Following the Finance Committee’s recommendation, the proposal was supported by 85 percent of the membership. We believe that developing the funding mechanism through the stakeholder process fostered a more open and transparent budgeting process that created the climate for a resolution on the funding proposal to be achieved.

33. With respect to the argument that wholesale purchasers of PJM transmission should not be required to pay for the cost of a RSC, we disagree. The costs PJM seeks to recover are legitimate business expenses of an RTO. PJM covers 14 regulatory commissions and has to interact with the regulatory commissions and their members on a regular basis. For example, PJM’s Regional Transmission Expansion Planning process identifies expansions that are necessary for reliability as well as those that will reduce costs. Siting and other issues relating to such expansions reside with the states. The formation of OPSI will help PJM to regularize its processes of interacting with the states to achieve the objectives of the RTO. OPSI, further, has the potential to bring public policy perspectives to PJM’s deliberations on issues such as the adequacy of resources to meet projected growth levels in the region. While OPSI is not a participant in the PJM market as a buyer or seller of energy or energy services, OPSI will consider PJM-related proposals affecting issues such as reliability, facility siting and transmission planning. Thus, we find that the collaboration between OPSI and PJM and other stakeholders will facilitate improvement in PJM’s market design, which benefits all market participants and approve the proposal.
34. The arguments that it is inappropriate to fund OPSI through the RTO or permit a 15 percent increase based on transmission usage are not convincing. In Order No. 2000, the Commission agreed with the National Association of Regulatory Utility Commissioners that state commissions “should fully participate in RTO formation and development.” The formation of OPSI provides state regulatory commissions the opportunity to fully participate in RTO formation and development. Additionally, we find that the advisory input from all stakeholders, including OPSI, is essential to the development of transmission arrangements and competitive markets in the PJM region. Well-functioning markets benefit all market participants including load.

35. In addition, the OPSI funding provision contains a safeguard against the recovery of excessive costs. The proposal includes PJM and stakeholder review of the yearly budget before PJM begins to collect any charges giving PJM and stakeholders review of the budget and an opportunity to object. As discussed below, we will require as a condition of approving this filing that the time period for such review be increased. As a further backstop, the proposed rate schedule requires that any OPSI budget submitted for a calendar year that includes an increase in excess of fifteen percent of the budget on file for the current calendar year will require the Commission’s approval by means of a section 205 filing by PJM.

36. We find that the OPSI annual budget proposal will permit stakeholders to properly evaluate the prudence of expenditures pursuant to an informational filing or, if applicable, a section 205 filing. OPSI commits to use the staff of member agencies to conduct much of the analysis and draftsmanship in pleadings submitted to the Commission in order to achieve cost savings. This is consistent with the OMS procedures and this approach will minimize the need for OPSI to request additional budget appropriations. Moreover, given that the OPSI annual budget will be deliberated through the PJM stakeholder process, all interested parties will have opportunity to object to OPSI’s costs each year.

37. However, we find that PJM has not shown that its proposal is just and reasonable as filed because it provides too little time for PJM and its stakeholders to review a proposed budget. We will require that PJM’s tariff include a deadline for providing OPSI’s proposed annual budget to the Finance Committee no later than June 1 of each year rather than August 1 as proposed. This will provide stakeholders additional time to review the annual budget elements and overall costs and raise any concerns prior to implementation.

38. Additionally, given that OPSI is in its initial stages of development, and that PJM’s mechanism for recovery of its costs may well change, we will require PJM to file a report on how the funding mechanism is operating three years from the date of this order. A three-year period will provide OPSI, PJM and the PJM ratepayers an opportunity to reevaluate the existing funding mechanism to ensure that it meets the parties’ objectives as a result of organization policies and procedure changes over time.
39. The Commission is not overstepping its authority by approving the funding mechanism for OPSI. PJM is an RTO with rates approved by the Commission. PJM has made a rate filing under section 205 of the FPA. We find that the funding of an RSC is a reasonable business expense of PJM to transact business that will benefit PJM’s ratepayers. OPSI will allow PJM to more effectively and efficiently coordinate its interaction with the 14 regulatory commissions with which it must deal in the PJM region by providing a conduit for information between the states and the RTO. Absent an organization like OPSI, PJM would have to interact with these state agencies on a less efficient one-on-one-basis. OPSI will benefit all market participants by mitigating regulatory costs uncertainties and delays. OPSI will also benefit market participants by coordinating consideration of issues such as reliability, facility siting, and transmission planning and by facilitating improvements in PJM’s market design.

40. We find PSEG’s argument that the proposed funding mechanism constitutes an unconstitutional exercise of power over free speech, is misplaced. The OPSI funding mechanism is a legitimate business expense of PJM to help coordinate its necessary activities with the states. The Commission’s establishment of a reasonable rate for a regulated entity is not in any way equivalent to the government compulsion of association or speech.\footnote{See Jackson v. Metropolitan Edison Co., 419 U.S. 345 (1974) (mere fact that a business is subject to state regulation does not by itself convert its action into that of the state); Allied Tube & Conduit Corp. v. Indian Head, Inc., 486 U.S. 492 (1988) (state acceptance of private standards code does not make the private standards-setter a governmental entity for purposes of the first amendment).} The United Foods case,\footnote{U.S. Department of Agriculture v. United Foods, 533 U.S. 405 (2002).} cited by PSEG, is inapposite. In that case, the Court found that a government requirement that businesses fund an advertising campaign violated the first amendment by compelling a party to subsidize speech with which it did not agree. But that case involved dues paid specifically to fund speech. In this case, PJM’s is providing funding to make its job of working with the states easier and more efficient.\footnote{Indeed, in United Foods, the Court recognized that a compelled subsidy is permissible when it is ancillary or germane to a valid cooperative endeavor. An RTO is such a cooperative venture which requires PJM to work cooperatively with all 14 regulatory commissions within its geographic territory.} The ability of any participant to express its views will not be constrained by this proposal.

41. We do not find that PJM’s expenditures here will adversely impact participation in New Jersey’s annual BGS auction and intrude on state prerogatives regarding funding of the BPU, as asserted by PSEG. The funding provided by PJM is designed to make PJM’s
dealings with its 14 regulatory commissions more efficient. Such funding is for a
different purpose and is independent of any funding by the State of New Jersey for the
BPU. Moreover, given that the funding proposal involves $425,000 spread out among all
transmission users in the PJM region that small amount should have minimal, if any,
effect on the BGS auction in New Jersey.\textsuperscript{14} We find no compelling evidence that the
mechanism to fund OPSI will greatly increase costs for customers participating in the
BGS auction and accept the proposal subject to the changes discussed herein.

42. As to the suggestion that the views of OPSI will have more weight than those of
other stakeholders, any views of OPSI filed with the Commission will be given no more
weight than any joint filing by the states would have been given. Any filing by OPSI will
be given careful review by the Commission, as do filings by other participants in the
process, but any final decision made by the Commission will be made under the
appropriate standard of the FPA.

VIII. Waiver

43. PJM states that it has served a copy of the October 28, 2005 and November 3,
2005 filing on all PJM Members and on all state utility regulatory commissions in the
PJM Region by posting this filing electronically and requests waiver of the requirement
to post by mailing paper copies. PJM states that it has served a copy of the November 3,
2005 filing on all persons on the service list for this docket, either electronically or in
paper copy, in accordance with the designations for such persons on the Commission’s
service list. The Commission grants the requested waiver subject to PJM providing paper
copies consistent with the Commission’s regulations to anyone who requests a paper
copy.

The Commission orders:

(A) The tariff sheets filed by PJM on October 28, 2005 listed in footnote 1 above
are rejected as moot.

\textsuperscript{14} Since 2002 the New Jersey BPU has auctioned off the provider of last of resort
service – also known as BGS – to New Jersey customers. According to the BGS auction
web site the four New Jersey Electric Distribution Companies – Public Service Gas &
Electric Company, Atlantic City Electric Company, Jersey Central Power & light
Company and Rockland Electric Company – have procured several billion dollars of
electric supply to serve their BGS customers through a statewide auction process held in
February. The Auction Process has consisted of two auctions that are held concurrently,
one for larger customers on an hourly price plan and one for smaller commercial and
(B) The tariff sheets filed by PJM on November 3, 2005 listed in footnote 1 above setting forth the OPSI funding mechanism are accepted subject to conditions as discussed above in the body of the order.

(C) To implement this filing, PJM must file revised tariff sheets within 30 days of the issuance of this order as discussed above in the body of the order.

(D) PJM’s request for waiver of the requirement to post by mailing paper copies is granted to the extent discussed above.

By the Commission.

(SEAL)

Magalie R. Salas, Secretary.
ORDER ENCOURAGING FURTHER STAKEHOLDER DISCUSSIONS AND
DENYING REHEARING IN PART

(Issued July 7, 2005)

1. On June 25, 2004, as amended on January 11, 2005, the Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont (the Petitioners) submitted a Joint Petition for Declaratory Order to form a New England Regional State Committee. The Petitioners intend to form a non-profit corporation, the New England States Committee on Electricity (NESCOE) that will serve as the New England region’s Regional State Committee. NESCOE will focus on developing and making policy recommendations related to resource adequacy and systems planning, and investigating and reporting to the New England Governors on policy questions concerning the possibility of creating a regional authority for siting of interstate transmission facilities. The Petitioners principally request that the Commission require ISO New England, Inc. (ISO-NE) and the New England participating Transmission Owners to make certain communications and to provide for funding of NESCOE through a regional tariff, as described below.

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1 Petitioners’ January 11 filing was styled as a motion to lodge the amended Petition. The Commission treated this filing as an amended Petition by noticing it and providing a comment period. To avoid any possible confusion, we will hereby grant the motion to lodge.
2. We commend the Governors for their commitment to form a Regional State Committee. However, for the reasons discussed below, the Commission will defer acting on the petition for declaratory order at this time and encourage Petitioners to undertake consultations with other stakeholders to address issues raised in this proceeding. While Petitioners propose many goals consistent with our previous descriptions of Regional State Committees, this proposal would benefit from further discussion at the stakeholder level to gain greater consensus. Customers will benefit from this order because it encourages participation between the Petitioners and other market participants within the existing stakeholder framework. As a result, this enhanced stakeholder process will facilitate improvements in the market design in New England.

3. This order also addresses requests for rehearing of one aspect of an order issued on December 30, 2004 in Docket No. ER05-134-000. In that order, the Commission rejected a proposed rate schedule to be used as a placeholder for a Regional State Committee to submit, justify, and collect its administrative costs, should such a committee be formed. This order clarifies the Commission’s rejection of that rate schedule and provides further guidance for the ISO-NE and stakeholders in creating a funding mechanism for a Regional State Committee.

I. Background

4. On September 8, 2003, a proposal to create a Regional State Committee was approved by the New England Governors. On October 31, 2003, ISO-NE and seven New England Transmission Owners proposed, in the context of the formation of a Regional Transmission Organization (RTO), that a Regional State Committee be a part of the structure of ISO-NE. On March 24, 2004, the Commission approved the ISO-NE proposal subject to the fulfillment of certain requirements. Petitioners now inform the Commission through this proceeding of the intended scope of responsibilities of the planned Regional State Committee and seek Commission action “so that NESCOE will have the tools, standing, and resources to assume the leadership role anticipated by the Commission.”

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2 ISO New England Inc., 109 FERC ¶ 61,383 (2004) (December 30 Order). The instant order responds to requests for rehearing of the Commission’s decision in the December 30 Order to reject Schedule 5. All other rehearing issues will be addressed in an order to be issued at a later date.


4 Petition at 4.
5. On November 1, 2004, ISO-NE filed, pursuant to section 205 of the Federal Power Act, revised tariff sheets to collect its administrative costs for calendar year 2005. The filing included a proposed Schedule 5 to account for the possibility that a Regional State Committee would be formed in New England and will seek to justify and recover its costs through the ISO’s tariff structure. In the December 30 Order, the Commission rejected the proposed rate schedule as unnecessary and premature, explaining:

The Commission does not believe that it is appropriate to provide a placeholder for the recovery of costs of a Regional State Committee that does not yet exist. We also believe that it is unnecessary for ISO-NE to recover any future costs it may incur for a Regional State Committee under a separate rate schedule; such costs should be included along with other regulatory costs in ISO-NE’s budget.[5]

II. Petition

6. Petitioners seek a declaratory order that would:

- Require that the ISO-NE and the New England participating Transmission Owners (TOs) provide NESCOE with written notice of any proposed additions or changes to market rules or tariffs within a reasonable time before filing the proposal;

- Require that the ISO-NE and the TOs give NESCOE a reasonable opportunity to make determinations and offer comments regarding any proposed additions or changes to market rules and tariffs that affect matters within the scope of NESCOE’s responsibility;

- Provide funding for NESCOE through a regional tariff administered by the ISO-NE and ultimately collected from all New England retail electricity customers; and

- Require the ISO-NE, the New England Power Pool (NEPOOL) and the TOs to file amendments to their respective Commission-jurisdictional tariffs and agreements to reflect the Commission’s intentions in the resulting declaratory order.6

5 December 30 Order at P 46.

6 Petitioners originally sought two additional types of requirements. These were deleted in the amended petition, and need not be addressed in this order.
7. In support of the Petition, the Governors state that, when NESCOE majority determinations are submitted to the Commission, they anticipate that these determinations will be accorded deference by the Commission.\textsuperscript{7}

A. Scope of NESCOE Responsibility

8. Petitioners propose that the scope of NESCOE jurisdiction, at the outset, should encompass at least two areas: resource adequacy and system planning and expansion. Petitioners state that NESCOE will also study and evaluate approaches to siting interstate transmission lines on a regional basis. Petitioners state that in the future, after consultation with other stakeholders, NESCOE could address such issues as security, fuel diversity, conservation, and the environmental impacts of power generation. Petitioners explain that the scope of NESCOE’s responsibility could be expanded or contracted only through a unanimous vote of its members.\textsuperscript{8}

B. The Role of NESCOE in Ensuring Adequate Resources

9. With respect to reserve margins, Petitioners state that NESCOE could provide a mechanism whereby the New England states can evaluate the appropriate degree of reliability risk and costs. Petitioners state that NESCOE would recommend policies designed to ensure that adequate resources are available to obtain a reliable electric system at a reasonable cost. Petitioners believe that the Regional State Committee offers an opportunity for the states to address the competing goals of limiting volatility in wholesale electricity prices and ensuring the development of sufficient resources to produce competitive pricing at all times. Petitioners state that in making its determinations, NESCOE would balance the various interests of generators, Transmission Owners, utilities, marketers, and customers, in addition to various public policy interests.

C. The Role of NESCOE in System Planning and Expansion

10. Petitioners state that the resource adequacy policies related to generation and demand-side resources alone may not be able to ensure regional electric reliability nor can they entirely eliminate persistent and costly congestion over transmission lines. Petitioners believe that, when the need for new transmission capacity is identified, regulatory considerations that generally do not exist for generation or energy efficiency come into play (particularly determinations by regulators of the need for the facility and approval of tariff adjustments to cover its cost). Petitioners state that

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\textsuperscript{7} Amended Petition at 3.

\textsuperscript{8} The Petitioners note that NESCOE would make an informational filing with the Commission if NESCOE determines to expand the scope of its responsibilities.
these decisions require tradeoffs among a variety of regional policy goals, e.g., determining whether the new lines will facilitate or impede the development of competitive generation and efficient markets and ensuring investments that are cost effective for customers. Petitioners state that NESCOE can recommend policies on transmission planning and expansion that will balance these policy goals. Petitioners also state that NESCOE would propose to this Commission the form of cost recovery treatment (e.g., inclusion in regional or local transmission tariffs) that the states could support to enable projects to go forward.

D. The Role of NESCOE in the Siting of Interstate Transmission

11. Petitioners believe that most states are reluctant to cede state siting jurisdiction to a multi-state agency. However, Petitioners state that the New England States might benefit from the regional focus that a multi-state advisory agency could bring to developing and maintaining an efficient and reliable regional transmission system. Petitioners assert that an interstate siting solution could creatively incorporate the regional view without eliminating state siting authority. Therefore, the Petitioners state that NESCOE would study and evaluate approaches to the siting of interstate transmission lines on a regional basis. Petitioners state that any NESCOE recommendations on transmission siting would be sent to the New England Governors for their action.

E. NESCOE Input and Determinations

12. Petitioners state that, to ensure that the New England States are afforded an appropriate level of input in decision-making affecting the New England region, they seek to coordinate NESCOE’s operations with ISO-NE’s and the Transmission Owners’ and deference from the Commission concerning NESCOE’s determinations. Petitioners state that, absent exigent circumstances justifying an emergency filing, ISO-NE and the Transmission Owners should provide NESCOE with written notice of their intent to add or make changes to market rules or tariffs. Petitioners also state that ISO-NE and the New England TOs must give NESCOE a reasonable opportunity to submit its determinations to them regarding any proposed additions or changes to market rules and tariffs that affect matters within the scope of NESCOE’s responsibility.

13. Petitioners state that NESCOE must also have the ability to initiate the Commission’s consideration of policy changes if ISO-NE or the New England TOs do not take action within their respective spheres. Petitioners state that instances in which NESCOE submits a Majority Determination to change or add to market rules or tariffs necessary to carry out a policy on a matter within the scope of its responsibility, if ISO-NE or the New England TOs do not file a proposal at the
Commission within a reasonable time seeking to implement NESCOE’s determination, NESCOE would file its determination under section 206 of the Federal Power Act.

F. NESCOE Funding and Governance

14. Petitioners request that the Commission order that NESCOE shall be funded by a regional tariff administered by ISO-NE and ultimately collected from all New England retail electricity consumers. Petitioners state that they will support the pass through of these costs in retail rates. The process envisioned by Petitioners is that: (1) NESCOE would prepare a budget each year following consultation with ISO-NE, NEPOOL and the Transmission Owners; (2) ISO-NE would include this separately identified amount as part of ISO-NE’s annual administrative budget submission to the Commission; and (3) NESCOE would provide any justification required for its budget proposal.

15. Petitioners state that this funding approach will assure NESCOE’s autonomy and its ability to make independent, unencumbered determinations. Petitioners explain that NESCOE will establish its budget based on its own assessment of the resources that will be necessary to assure a separate source of necessary information and analysis. Petitioners assert that because ISO-NE will simply act as the funding conduit and may not make substantive changes to NESCOE’s identified requirements, NESCOE will not be subject to potential influence from ISO-NE based on the power of the purse.

16. Petitioners state that, for a determination to become a Majority Determination of NESCOE, it must pass two voting thresholds. Petitioners explain that NESCOE would first vote on a “one-state-one-vote” basis, and a motion would be successful if it received the affirmative support of at least four states out of six. Petitioners also explain that a second vote would be taken on a “proportionate consumption” basis, which would preclude one state from being able to prevent a motion from passing that otherwise had the support of five other states. Petitioners state that the scope of NESCOE’s jurisdiction over subjects other than resource adequacy and system planning could be expanded (or contracted) only by unanimous agreement of the member states.

III. Notice of Filings and Responsive Pleadings

17. Notice of the petition for declaratory order was published in the *Federal Register*, 69 Fed. Reg. 41,467 (2004), with protests and interventions due on or before July 16, 2004. Timely motions to intervene raising no substantive issues were filed by Florida Power & Light Company, Select Energy, Inc., the New England Conference of Public Utilities Commissioners (NECPUC), and Exelon Corporation. Timely motions to intervene and protests were filed by: New England Consumer-
Owned Entities (Consumer-Owned Entities);\(^9\) Indicated Suppliers;\(^10\) the Connecticut Office of Consumer Counsel and New Hampshire Office of Consumer Advocate (Connecticut OCC and New Hampshire OCA); the Edison Electric Institute and Alliance of Energy Suppliers (EEI); ISO-NE; New England TOs;\(^11\) and NEPOOL Participants Committee (NEPOOL). In addition, Northeast Energy Efficiency Partnerships, Inc. filed comments in support of the petition without moving to intervene.

18. The following filed motions to intervene out-of-time: Duke Energy North America, LLC (Duke); Constellation Power Source, Inc. and Constellation NewEnergy, Inc. (Constellation); the Attorney General of Rhode Island; NRG Companies (NRG); and the Electric Power Supply Association (EPSA). NRG and EPSA protest the filing.

19. On August 20, 2004, the Petitioners submitted a motion to submit an answer to the protests and an answer.

20. Notice of the motion to lodge the amended petition was published in the Federal Register, 70 Fed. Reg. 5990 (2005), with protests and interventions due on or before February 7, 2005. NEPOOL and NRG commented on or protested the motion,

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9 The New England Consumer-Owned Entities are: Connecticut Municipal Electric Energy Cooperative; Massachusetts Municipal Wholesale Electric Company; Vermont Public Power Supply Authority; New Hampshire Electric Cooperative, Inc.; Chicopee Municipal Lighting Plant of the City of Chicopee, Massachusetts; Braintree Electric Light Department (Braintree); Reading Municipal Light Department (Reading); and Taunton Municipal Lighting Plant (Taunton).

10 Indicated Suppliers include: Calpine Corporation and Calpine Energy Services, L.P.; FPL Energy, LLC; Mirant Americas Energy Marketing, LP; Mirant New England, Inc.; Mirant Canal, LLC; Mirant Kendall, LLC; and PSEG Energy Resources & Trade LLC.

11 The New England Transmission Owners are: Bangor Hydro-Electric Company; Central Maine Power Company; NSTAR Electric & Gas Corporation (on behalf of its operating affiliates); New England Power Company; Northeast Utilities Service Company (on behalf of its operating company affiliates); The United Illuminating Company; and Vermont Electric Power Company.
and Wellesley Municipal Light Plant (Wellesley) filed a motion to intervene. A group of municipals (Braintree, et al.)\textsuperscript{12} filed a request for rejection in part or, in the alternative, protest and request for hearing.

21. Most commenters support the concept of a Regional State Committee for New England, particularly for its proposed role in transmission siting and the development of transmission infrastructure. EPSA, for example, believes that a Regional State Committee can help ensure that all parties work effectively and efficiently together to seek regional solutions on resource adequacy and facility planning. EPSA, Indicated Suppliers and other are concerned, however, about the proposed provision to allow NESCOE to expand its scope of responsibility unilaterally through a unanimous vote of its members. These parties contend that the Regional State Committee’s purview must be clearly defined and approved prior to implementation; they assert that any expansion of responsibility should occur only after Commission approval.

22. Other objections are that Regional State Committee determinations should not be accorded any greater deference than other parties’ positions, that the Joint Petition has not clearly explained how NESCOE will interact with other State representatives, and that the Joint Petition proposes responsibilities for NESCOE that exceed those in the White Paper.\textsuperscript{13} Braintree, et al., argue that the Petitioners do not explain what “deference” or “great deference” mean, although Petitioners seek more weight for Regional State Committee position than for the positions of either the RTO or the region’s Transmission Owners. Braintree, et al., contend that there is no basis for the deference that is sought, and assert that the Petitioners and ISO-NE offer no appropriate limiting principle to circumscribe the deference to which they assert the Regional State Committee should be entitled.

VI. Discussion

A. Procedural Matters

23. Pursuant to Rule 214 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2004), the timely, unopposed motions to intervene in Docket No. EL04-112-000 serve to make the entities that filed them parties to this

\textsuperscript{12} The municipal utilities include Braintree, Reading, Taunton, and Wellesley.

proceeding. We will grant the motions to intervene out-of-time filed by Duke, Constellation, NRG, EPSA, and the Attorney General of Rhode Island given their interest in this proceeding, the early stage of this proceeding, and the absence of any undue prejudice or delay.

24. Rule 213(a)(2) of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2004), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept Petitioners’ answer because it has provided information that assisted us in our decision-making process.

B. Formation of the Regional State Committee

25. We commend the New England Governors for their commitment to form a Regional State Committee, and we agree that the Committee has much to offer in formulating policies for the New England region. The Commission has already approved, in the March 2004 Order, an RTO organizational structure that contemplates the participation of a Regional State Committee in the stakeholder process.\footnote{14} For example, section 3.04(h) of the ISO-NE Transmission Operating Agreement provides for Regional State Committee input into regional cost allocation section 205 filings. This assures the Regional State Committee the right to provide Transmission Owners with an alternate proposal (if the Transmission Owners and the Regional State Committee are unable to agree on changes to regional cost allocation provisions) which will be “considered on an equal footing” with the Transmission Owners’ proposal.\footnote{15} Additionally, section 3.04(h) provides for a stakeholder process for regional rate filings. These provisions, which were agreed to by the parties in the RTO proceeding, include requirements for notification to and consultation with the Regional State Committee in advance of making a section 205 filing.

26. A major concern of protesters in this proceeding is that many of Petitioners’ controversial proposals have not been vetted through a stakeholder process. We believe that the best way to implement a new institution such as NESCOE which will be involved in many key transmission-related policy decisions for the region is through a consensual, voluntary process. Accordingly, we will encourage Petitioners to resolve these issues first through existing stakeholder procedures, and we will defer

\footnote{14} See March 2004 Order, 106 FERC ¶ 61,280 at P 71-79.

\footnote{15} ISO-NE Transmission Operating Agreement, filed in Docket No. RT04-2-000, at section 3.04(h).
acting on the petition for declaratory order at this time to allow these discussions to proceed. We will direct ISO-NE to submit status reports to the Commission regarding the progress of discussions on Regional State Committee issues, the first to be filed 90 days after the date of this order, and every 90 days thereafter until discussions are concluded.

C. **Regional State Committee Funding**

**Comments**

27. ISO-NE contends that a separate Regional State Committee budget proposal should contain rate recovery provisions. In addition, the New England TOs and the ISO-NE argue that the Regional State Committee budget should be developed through a stakeholder process.

28. ISO-NE states that it has no objection to collecting NESCOE’s revenue requirements from RTO customers, as an accommodation to NESCOE, but seeks clarification from the Commission that the NESCOE tariff and budget shall be separate and distinct from the ISO-NE’s self-funding mechanisms and budget, and that the Commission’s evaluation of NESCOE’s proposed budget and recovery mechanism will be separate from its evaluation of the ISO-NE’s proposed budget and recovery mechanism. ISO-NE states that it is concerned that joint consideration by the Commission of the funding of the ISO-NE and NESCOE could delay and compromise the ISO-NE’s ability to collect its required revenues and could threaten the ISO-NE’s ability to carry out its mission.

29. Further, ISO-NE requests that the Commission determine that NESCOE, and not the ISO, will be required to demonstrate the justness and reasonableness of the Regional State Committee budget and the rate design used to collect the Regional State Committee revenue requirement. Moreover, ISO-NE and the New England TOs argue that NESCOE should be required to submit its budget to the ISO-NE and RTO stakeholders in advance of its submission to the Commission, in order to obtain ISO-NE and stakeholder input.

30. Consumer-Owned Entities, Connecticut OCC and New Hampshire OCA, NEPOOL, NRG and Indicated Suppliers raise funding concerns and argue that the retail costs should not be collected under an RTO tariff. Consumer-Owned Entities contend that there is no proposal presented here by an RTO to include Regional State Committee expenses in the RTO’s budget, and that the White Paper offers no support for recovering such expenses through a wholesale tariff where (as here) the RTO operates on a non-profit basis and has no funds of its own with which to reimburse the
out-of-pocket expenses referenced in the White Paper. Consumer-Owned Entities argue that the Regional State Committee is not proposing any real budgetary process with respect to ISO-NE customers’ involuntary funding of Regional State Committee activities through the RTO tariff.

31. In response to the amended Petition, Braintree, et al., argue that state-level political judgments and public policy balancing – the types of activities promised to be offered by the proposed Regional State Committee – represent a class of matters that the Commission has consistently held are not subject to cost recovery through the charges applicable under wholesale transmission tariffs, and should instead be the subject of cost recovery under state-supervised retail tariffs.

32. Consumer-Owned Entities and others contend that there is no limit on Regional State Committee billings to wholesale customers, and the Joint Petition states that technical support for NESCOE members may require expertise in engineering, economics, legal and policy analysis, regional planning, and public information, all of which will apparently be siphoned from wholesale customers. These parties argue that there is nothing that justifies making the Regional State Committee a roving commission for mandates that the States themselves have not chosen to fund by the conventional and accepted means of taxation or utility assessments. NRG asserts that, if NESCOE desires to conduct autonomous studies to critique the technical analyses of ISO-NE, the states should fund such studies and collect the costs as they are permitted to through their usual sources of funding. In response to the amended Petition, Braintree, et al., contend that compelled funding at the wholesale level interferes with the ability of state legislatures to control the activities of state agencies through funding decisions associated with the traditional means of funding those agencies.

33. NEPOOL and others argue that there is no basis under the Federal Power Act to require involuntary funding of NESCOE’s activities by ISO-NE Tariff customers. Indicated Suppliers assert that, in the event that the Commission accepts this funding mechanism, however, the Commission should state explicitly that Network Load should bear these expenses pursuant to a tariff on file with the Commission and subject to its review, since NESCOE would ostensibly represent the interests of these constituents. In response to the amended Petition, NEPOOL contends that the Petitioners have failed to consult with NEPOOL – the organization that represents all of the sectors of the wholesale electric industry in New England – prior to filing this Amended Petition, while at the same time seeking special consultative rights for themselves and funding within the RTO arrangements.
34. Petitioners assert in their answer that, for NESCOE to maintain its independence, ISO-NE, and the Transmission Owners should not have a veto over planned NESCOE expenditures, thereby potentially influencing the substance of NESCOE’s determinations. Petitioners state that NESCOE will need to have separate resources to conduct its own analyses and to present its own positions. Petitioners contend that, nevertheless, any party will have the right to challenge NESCOE’s budget requests as excessive, duplicative, or otherwise unjust and unreasonable. Petitioners argue that NESCOE will develop budget procedures and its annual budget with the RTO, NEPOOL, and the Transmission Owners, and the Commission will finally approve NESCOE’s budget separately from the ISO-NE budget. Petitioners contend that all of these mechanisms will ensure that NESCOE does not have the “blank check” that some protesters apparently fear.

Related Requests for Rehearing in Docket No. ER05-134-002

35. ISO-NE, NEPOOL, and a group of municipalities (the Municipals)\(^\text{16}\) filed requests for rehearing regarding the December 30 Order’s rejection of Rate Schedule 5.\(^\text{17}\)

36. ISO-NE objects to the Commission’s rejection of proposed Schedule 5. It seeks clarification, or, in the alternative, rehearing of the “apparent requirement that the ISO include the costs of a Regional State Committee in the ISO’s core operating budget in a manner that would require the ISO to justify the budget of a separate, purposely independent organization.”\(^\text{18}\) Initially, ISO-NE argues that its proposed Schedule 5 should not be rejected because, as filed, it could impose no cost, burden or harm on any customers. Further, ISO-NE asserts that a finding that Schedule 5 is “unnecessary and premature” does not render it unjust and unreasonable; as such, it is lawful and must be accepted for filing. More substantively, ISO-NE asserts that it cannot attest to the level of, or need for, costs incurred by the Regional State Committee, and argues that the Regional State Committee’s costs should not be included in ISO-NE’s core operating budget. Rather, ISO-NE asks the Commission to recognize the two entities’ separate corporate identities and to allow the Regional State Committee’s costs to be recovered under a separate schedule so the ISO could simply act as a funding conduit. ISO-NE concludes:

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\(^{16}\) The Municipals include the Massachusetts Municipal Wholesale Electric Company, Braintree, Reading, Taunton, and Wellesley.

\(^{17}\) These parties and others also sought rehearing of other aspects of the December 30 Order. Those issues were addressed in a separate order issued on April 19, 2005. \textit{ISO New England Inc.}, 111 FERC ¶ 61,096 (2005).

\(^{18}\) ISO-NE rehearing at 1.
Any amount of the RSC’s budget not found just and reasonable by the Commission could be excluded from the ISO’s budget, yet the ISO might still be obligated to pay the full amount billed to it by the RSC. This is clearly untenable.\footnote{ISO-NE rehearing at 5-6.}

37. NEPOOL and the Municipals support the Commission’s finding that Schedule 5 was premature but object to the idea of including the Regional State Committee’s costs along with other regulatory costs in ISO-NE’s budget. The Municipals argue that this dictum from the December 30 Order is unnecessary and contrary to law. Because the costs incurred by the Regional State Committee are not necessary to ISO-NE’s provision of service to its customers and are not “regulatory costs,” the Municipals charge that the ISO’s customers should not have to reimburse those costs.

38. NEPOOL similarly argues that Regional State Committee costs should not be forced to be paid by ISO-NE “and transformed thereby into ISO-NE expenses.”\footnote{NEPOOL rehearing at 4.} NEPOOL notes that ISO-NE’s budget process included in the Participants Agreement does not reflect agreement for participants to pay the costs of a Regional State Committee for the region and states that the issue of Regional State Committee funding is not ripe for Commission consideration because no proposal has been presented for discussion among NEPOOL stakeholders and there has been no agreement as to necessary changes in the RTO governing documents. NEPOOL complains that if the Commission prematurely concludes that ISO-NE should be required to cover these costs, then “the Commission would deprive the participants of their right to provide meaningful input into both the budget and the cost allocation that could affect them directly.”\footnote{Id. at 5.}

**Commission Response**

39. In response to Braintree, et al.’s argument that cost recovery is unprecedented, we note that funding for two existing Regional State Committees, the Organization of MISO States (OMS), and the Southwest Power Pool’s Regional State Committee (SPP), are budgeted through ISOs/RTOs. Specifically, a budget is prepared by the
OMS or SPP Regional State Committee and presented to the respective ISO Board of Directors for approval.\footnote{22} If New England participants agree to a similar mechanism, then parties would have input as to NESCOE’s budget, and ISO-NE’s Board would have final approval. Such a process could relieve concerns regarding ISO-NE’s independence and its ability to justify the proposed budget.

40. Any cost recovery mechanism agreed to by the parties should result in a budget establishing reasonable costs. This budget should be transparent and indicate clearly the anticipated, future costs associated with the establishment and operation of NESCOE, identified separately from those of ISO-NE. This would be possible by including NESCOE’s budget as a line item in ISO-NE’s annual filing to recover its administrative costs. Other arrangements may also be acceptable, but we do not believe that a separate schedule is necessary.

41. Accordingly, at this time we deny rehearing of our rejection of ISO-NE’s Schedule 5. We reiterate our finding that the proposed Schedule 5 is premature. Because a funding mechanism for NESCOE has not been deliberated by the participants in New England, there is no certainty that a separate schedule will eventually be agreed upon and utilized. In response to ISO-NE’s assertion that we may not reject a rate filed under section 205 of the Federal Power Act unless it is found to be unjust and unreasonable, we observe that the Commission has rejected tariff provisions as premature in other instances.\footnote{23} Further, because the Commission is not ruling on any particular funding arrangement at this time, we will dismiss additional rehearing arguments as speculative and not yet ripe for decision.

42. We encourage the parties in this proceeding to reach a mutually agreeable resolution of all issues surrounding the creation of this Regional State Committee, and if the parties conclude, in the context of a global agreement, that the best manner of presenting NESCOE’s budget to the Commission is as a separate schedule within ISO-NE’s administrative cost filing, then we may reconsider our holding.


The Commission orders:

(A) The Commission hereby defers action on the petition for declaratory order until completion of further stakeholder discussions, as discussed in the body of this order.

(B) ISO-NE is hereby directed to submit reports on the status of the stakeholder discussions every 90 days, as discussed in the body of this order.

(C) The requests for rehearing of the issues discussed above are hereby denied.

(D) The Petitioners’ motion to lodge is hereby granted.

By the Commission. Commissioner Kelly concurring with a separate statement attached.

( S E A L )

Magalie R. Salas,
Secretary.
KELLY, Commissioner, concurring:

This order defers acting on the joint petition for declaratory order filed by the Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to form a New England Regional State Committee. The order finds that the Governors’ proposal would benefit from further discussion at the stakeholder level to gain greater consensus. Although I do not object to using the existing ISO-NE stakeholder framework as a forum for discussion, I would have preferred that the Commission act on the proposal at this time.
ORDER ON REHEARING

(Issued October 1, 2004)

1. By order issued February 10, 2004, the Commission conditionally granted Southwest Power Pool, Inc.’s (SPP) application for recognition as a Regional Transmission Organization (RTO). Pursuant to Order Nos. 2000 and 2000-A, the Commission directed SPP to fulfill several requirements prior to being recognized as an RTO. In this order, we address requests for rehearing of the February 10 Order. As discussed below, we will grant in part, and deny in part, the rehearing requests and direct a further compliance filing.

2. Our action here encourages RTO participation and ensures the establishment of efficient and reliable markets throughout the region, while preventing undue discrimination or preference in the provision of electric transmission services.

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Background

Description of SPP

3. SPP is an Arkansas non-profit corporation, serving more than four million customers in a 250,000 square mile area, covering all or part of the States of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. SPP’s membership includes 14 investor-owned utilities, six municipal systems, eight generation and transmission cooperatives, three state authorities, one federal power marketing agency, two independent power producers, and 16 power marketers.

4. SPP became a regional reliability council in 1968 and has administered a regional open access transmission service tariff (OATT) for its member Transmission Owners (TOs) since 1998.

3 Exhibit No. SPP-1 (Testimony of Nicholas A. Brown) and Attachment C (SPP Regional Map).

4 Id. SPP existing members are: American Electric Power Company-Public Service Company of Oklahoma and Southwestern Electric Power Company; Aquila, Inc.-Missouri Public Service Company, St. Joseph Light & Power Company, and WestPlains Energy; Cleco Power LLC; Entergy Services, Inc.; Exelon Power Team; Kansas City Power & Light Company; Oklahoma Gas and Electric Services; Southwestern Public Service Company; The Empire District Electric Company; Westar Energy-Western Resources, Inc. and Kansas Gas & Electric Company; Arkansas Electric Cooperative Corporation; East Texas Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; Midwest Energy, Inc.; Northeast Texas Electric Cooperative; Sunflower Electric Power Corporation; Tex-La Cooperative of Texas, Inc.; Western Farmers Electric Cooperative; City of Clarksdale, Mississippi; City of Lafayette, Louisiana; City Power & Light, Independence, Missouri; City Utilities, Springfield, Missouri; Public Service Commission of Yazoo City, Mississippi; The Board of Public Utilities, Kansas City, Kansas; Grand River Dam Authority; Louisiana Energy & Power Authority; Oklahoma Municipal Power Authority; Southwestern Power Administration; Calpine Energy Services, L.P.; InterGen Services, Inc.; Tenaska Power Services Company; Aquila Power - Aquila, Inc.; Cargill-Alliant, LLC; Cinergy Corporation; Constellation Power Source; Coral Power LLC; Duke Energy Trading & Marketing; Dynegy Marketing & Trade; Edison Mission Marketing & Trading, Inc.; El Paso Merchant Energy, L.P.; Mirant Americas Energy Marketing, L.P.; NRG Power Marketing, Inc.; TXU Energy Trading Company; and Williams Energy Marketing & Trading Company.
5. On October 15, 2003, SPP submitted the RTO application at issue in this proceeding. SPP’s filing included, among other things, proposed revisions to its Bylaws and Membership Agreement, as well as changes to its OATT.

**February 10 Order**

6. In the February 10 Order, we recognized that SPP had made significant steps toward satisfying all of the prerequisites for qualification as an RTO under Order Nos. 2000 and 2000-A. However, we found that SPP must make additional tariff, organizational and other changes prior to receiving final RTO authorization. As discussed more fully below, we directed SPP to: (1) implement its independent Board and modify its governance structure; (2) expand the coverage of its tariff to assure that SPP is the sole transmission provider; (3) obtain clear and sufficient authority to exercise day-to-day operational control over the appropriate transmission facilities within its footprint; (4) put in place an independent market monitor to monitor the competitiveness and efficiency of the market; (5) obtain clear and precise authority to independently and solely determine which projects to include in the regional transmission plan, and prioritize those projects; and (6) file with the Commission a seams agreement with the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). We also directed SPP to file, pursuant to section 205 of the Federal Power Act (FPA),\(^5\) its revised Bylaws and revised Membership Agreement, as modified in accordance with the February 10 Order. We further directed SPP to file its operating budget, for informational purposes, within 90 days of the date it obtains operational authority over transmission facilities within its footprint.

**Requests for Rehearing**

7. The following parties timely filed requests for rehearing of the February 10 Order\(^6\): TDU Intervenors\(^7\); State Regulators\(^8\); Westar Energy, Inc. and Kansas Gas and Electric

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\(^6\) All entities that filed rehearing requests will be referred to collectively as the “parties.”

\(^7\) TDU Intervenors include: the Missouri Joint Municipal Electric Utility Commission, the Oklahoma Municipal Power Authority, and the West Texas Municipal Power Agency.

\(^8\) State Regulators include: the Arkansas Public Service Commission, the Louisiana Public Service Commission, and the New Mexico Attorney General. The New
Company (collectively, Westar); East Texas Cooperatives\(^9\); Kansas Corporation Commission (Kansas Commission); Golden Spread Electric Cooperative, Inc. (Golden Spread); American Electric Power System (AEP West)\(^{10}\); Kansas City Power & Light Company (KCPL); Southwestern Public Service Company (Southwestern Public Service); and the Oklahoma Corporation Commission (Oklahoma Commission). The Missouri Public Service Commission (Missouri Commission) filed an untimely rehearing request.

8. Generally, the parties are pleased with the Commission’s decision to conditionally grant RTO status to SPP,\(^{11}\) but they dispute aspects of the February 10 Order. The rehearing arguments are addressed, by issue, below.

**Procedural Matters**

9. The Missouri Commission filed its request for rehearing one day out of time. Section 313(a) of the FPA\(^{12}\) requires all requests for rehearing to be filed within 30 days, thus, we are without jurisdiction to consider the Missouri Commission’s rehearing request. Nevertheless, the Commission will address the Missouri Commission’s arguments, to the extent those arguments are reflected in timely rehearing requests.

Mexico Attorney General separately filed additional comments in support of its request for rehearing.

\(^{9}\) East Texas Cooperatives include: East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; and Tex-La Electric Cooperative of Texas, Inc.

\(^{10}\) AEP West includes: Southwestern Electric Power Company and Public Service Company of Oklahoma, both of which are operating companies of AEP.

\(^{11}\) See, e.g., TDU Intervenors at 1; Southwestern Public Service at 1; State Regulators at 1. Indeed, Southwestern Public Service states on rehearing that it has decided to pursue participation in SPP as a result of certain conditions the Commission directed in the February 10 Order.

\(^{12}\) 16 U.S.C. § 825l.
10. Further, on February 27, 2004, Crescent Moon Group\textsuperscript{13} filed a motion for late intervention, and, on May 24, 2004, Louisiana Energy and Power Authority and the Municipal Energy Agency of Mississippi (collectively, LEPA) jointly filed a motion to late intervention. When late intervention is sought after the issuance of a dispositive order, the prejudice to other parties and burden upon the Commission of granting the late intervention may be substantial. Thus, movants bear a higher burden to demonstrate good cause for granting such late intervention. Crescent Moon Group offers no reason for failing to intervene in a timely manner; LEPA, which is a member of SPP, states that it failed to intervene earlier because of uncertainty regarding whether Entergy might become a participant in SPP. We find that Crescent Moon Group and LEPA have failed to satisfy the higher burden of justifying late intervention, and, accordingly, we will reject their motions.\textsuperscript{14}

\textbf{Cost Benefit Analysis Prior to Granting RTO Status}

11. As an initial matter, the New Mexico Attorney General asserts that the Commission may not allow the SPP RTO to proceed into Day 1 without a cost/benefit analysis showing that the RTO will benefit users of SPP’s system and result in just and reasonable rates. The New Mexico Attorney General argues that, because the Commission did not require a cost/benefit analysis prior to conditionally granting RTO status to SPP, the Commission violated the FPA.\textsuperscript{15}

\textbf{Discussion}

12. We will deny rehearing on this issue. The Commission promulgated Order Nos. 2000 and 2000-A pursuant to our authority under the FPA,\textsuperscript{16} and those orders do not require a cost/benefit analysis demonstrating that a specific RTO proposal will result in just and reasonable rates, prior to RTO approval. Rather, as discussed in Order No. 2000, \textsuperscript{13} Crescent Moon Group consists of: Basin Electric Power Cooperative, Heartland Consumers Power District, Minnkota Power Cooperative, Inc., NorthWestern Energy, Sunflower Electric Power Corporation, and the Upper Great Plains Region of the Western Area Power Administration.

\textsuperscript{14} We note that in our order addressing SPP’s compliance filing to the February 10 Order, we grant LEPA’s motion for intervention, since it is timely with regard to SPP’s compliance filing.

\textsuperscript{15} New Mexico Attorney General at 3-4.

\textsuperscript{16} See Order No. 2000 at 30,993 and 31,039.
the Commission believes that RTOs in general offer numerous benefits that will help ensure just and reasonable rates for jurisdictional services.\textsuperscript{17}

13. Moreover, with specific regard to this case, we have accepted SPP’s commitment to conduct a cost/benefit analysis prior to implementation of Phases 2 and 3 of its market development plan.\textsuperscript{18} We believe that this approach will achieve the same goals as conducting one cost/benefit analysis prior to granting SPP RTO status, by ensuring that the expenditure of funds for each phase will result in particular benefits to customers in SPP’s region.

14. In addition, we note that, on March 19, 2004, the Commission held a technical conference (March 19 Outreach Meeting) that addressed issues relevant to SPP’s RTO proposal, including whether SPP must perform a cost/benefit analysis prior to achieving RTO status. At the March 19 Outreach Meeting, representatives from several state commissions asserted that SPP facilities within their respective jurisdictions must apply for state approval to join an RTO. The state commissions further indicated that they might require a cost/benefit analysis demonstrating the benefits, or non-detrimental effects, of RTO formation. However, they also indicated that these state reviews could proceed in conjunction with Commission review.\textsuperscript{19}

\textsuperscript{17} See \textit{id.} at 30,993 and 31,017.

\textsuperscript{18} As detailed in the February 10 Order, SPP’s proposed market development plan included three phases: (1) imbalance market and market monitoring, which, in turn, will be introduced in three increments, to be fully implemented in November 2004; (2) financial transmission rights for market-based congestion management, to be implemented in November 2005; and (3) regional ancillary service mechanisms, to be implemented in Fall 2005.

\textsuperscript{19} See Transcript of March 19 Outreach Meeting in Docket Nos. RT04-1-000, \textit{et al.}, at 140-155.
RTO Characteristics

Scope and Configuration

RTO Membership Withdrawal Provisions

February 10 Order

15. In the February 10 Order, the Commission conditionally approved the revised Membership Agreement and directed SPP to file it pursuant to section 205 of the FPA. With regard to the withdrawal provisions, we noted that, under section 4.1.1 of both the then-current and revised Membership Agreement, a TO may withdraw from SPP only upon providing 12 months’ notice, pursuant to section 205 of the FPA, and that, “with regard to any withdrawal by a FERC public utility, the withdrawal shall not become effective until FERC has accepted the notice of withdrawal or otherwise allows such withdrawal.” We interpreted this provision to mean that no public utility may withdraw without an affirmative finding by the Commission that such a withdrawal is just and reasonable. We further emphasized our support for continued membership in the SPP RTO, which we believe, with the additional conditions imposed by the February 10 Order, will result in a viable functioning RTO.

Requests for Rehearing

16. On rehearing, some parties argue that, in approving the proposed withdrawal provisions, the Commission did not adequately ensure SPP’s continued viability as an RTO. TDU Intervenors assert that TOs should be required to remain in the SPP RTO for at least five years, so that they cannot use the threat of departure to make certain demands. Golden Spread argues that, if a TO’s notice of intent to withdraw is contested, the Commission should immediately issue a “show cause” order requiring the TO to demonstrate why any authority previously granted to it to sell generation or ancillary services at market-based rates should not be revoked.

20 February 10 Order at P 65-66.


22 February 10 Order at P 66.

23 TDU Intervenors maintain that AEP’s membership is of greatest concern, to the extent that AEP West’s facilities are essential to the connectivity of the rest of SPP.

24 Golden Spread at 4-5.
17. On the other hand, other parties argue that, by conditionally approving the revised Membership Agreement, including the withdrawal provisions, the Commission exceeded, or could be perceived as exceeding, its jurisdiction. The Kansas Commission and State Regulators argue that the Commission usurped state authority to determine which utilities within their respective boundaries may join an RTO. These state commissions, as well as Southwestern Public Service, AEP West, and KCPL, argue that the withdrawal provisions convert, or can be viewed as converting, current SPP members into involuntary RTO participants, irrespective of whether those members obtained prior state approvals to participate in the RTO. This effect, they argue, is inconsistent with the spirit of Order No. 2000, which promotes voluntary RTO formation, and violates judicial precedent concerning the limits of Commission jurisdiction. The New Mexico Attorney General argues that, while the Commission might have authority to determine whether the entry and exit rights provided by an RTO are just and reasonable, the Commission may not prohibit a utility from leaving an RTO. Notwithstanding the Commission’s conditional approval of the revised Membership Agreement and SPP’s RTO proposal in general, Southwestern Public Service and AEP West seek Commission clarification that state commissions will be given adequate opportunity to review a utility’s RTO membership.

18. State Regulators further argue that, by requiring SPP to modify and file the revised Membership Agreement and Bylaws as a precondition to RTO status, the Commission exceeded its jurisdiction under the FPA. They claim that, while the FPA might express a policy of promoting interconnection, it does not empower the Commission to regulate the terms of individual interconnection agreements.

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25 Southwestern Public Service further argues that the SPP Board of Directors voted, without member approval, to reconstitute SPP as an RTO.

26 These parties cite Atlantic City v. FERC, 295 F.3d 1 (2002).

27 State Regulators at P 22. State Regulators contend that the Commission directed SPP to modify the agreement to state that “no public utility may withdraw without an affirmative finding by this Commission and a finding that such a withdrawal is just and reasonable,” and that the Commission may not mandate the terms of the Membership Agreement in such a manner.

19. Moreover, State Regulators argue that, under section 5.1.b of the revised Membership Agreement, Commission approval for withdrawal is not required. They maintain that any SPP member has an absolute right to withdraw without obtaining Commission authorization, if the Commission modifies the Membership Agreement, as it did in the February 10 Order.

Discussion

20. We will deny rehearing on our ruling that no public utility may withdraw from SPP membership without Commission approval that such withdrawal is just and reasonable. Although State Regulators argue that, under section 5.1.b of the Membership Agreement, Commission approval for withdrawal is not required, we disagree. We note that no signatories to the Membership Agreement or SPP have sought rehearing contending that section 5.1.b applies to the instant facts. As we pointed out in the February 10 Order, SPP’s Membership Agreement and the duties and obligations of its members under that agreement are subject to our jurisdiction, and as such, we can direct SPP and its members to comply with certain requirements.

21. In making our determination in the February 10 Order, we reviewed the Membership Agreement in its entirety. Our decision in the February 10 Order is based on section 4.1.1 which requires TOs to provide notice of withdrawal at least 12 months prior to the intended date of withdrawal and that Commission approval is required to effectuate such withdrawal. This requirement is not dependent on, qualified by, or

29 State Regulators state the Commission’s position is inconsistent with the express terms of the Membership Agreement, which allow a member to withdraw in these circumstances without seeking prior approval from the Commission. Section 5.1.b reads as follows:

In the event of any order or decision by FERC or by a court modifying this Agreement of the OATT submitted as part of seeking FERC acceptance or approval, that in the judgment of Member adversely affects it, then Member, at its sole discretion, may withdraw from this Agreement by providing written notice to the President of SPP no later than thirty days after such order or decision without receiving any FERC authorization.

30 State Regulators at 20-21.

31 February 10 Order at P 64.

32 See Exhibit No. SPP-4 (SPP’s Revised Membership Agreement).
conditioned by reference to any other section of the Agreement, including section 5.1.b to which the State Regulators refer.

22. We have also reviewed section 5.1 of the Membership Agreement, titled “Regulatory and Other Authorities,” which states that its subsections (5.1.a and 5.1.b) address “a Member’s rights and obligations in the event regulatory and other approvals or acceptances are not obtained or changes are required” with respect to the initial effectiveness of the agreement. Section 5.1.a provides for Member’s rights in such circumstances by stating, in part, “[i]n the event that FERC disapproves or refuses to accept this Agreement or the changes to the OATT developed together with this Agreement, then this Agreement shall cease to be effective . . . .” Section 5.1.b also addresses certain Member rights at the time prior to the initial effectiveness of the Agreement, by stating, in part, “in the event of any order or decision by FERC or a court modifying this Agreement or the OATT submitted as part of the initial filing seeking FERC acceptance or approval, that in the judgment of Member adversely affects it, then Member . . . may withdraw from this Agreement . . . .” In this case, we have not approved or refused to accept the SPP Membership Agreement; we previously accepted the Membership Agreement as an “initial filing,” effective January 1, 2000. Accordingly, section 5.1 is not applicable to the instant case.  

23. Nor have we required any changes to the Agreement pursuant to section 206 of the FPA. Here, the Commission has reviewed a voluntary filing pursuant to section 205 of the FPA, where SPP sought to be designated as an RTO, and the Commission, rather than “issuing an order or decision modifying the Membership Agreement,” issued an order setting forth the requirements with which SPP must comply in order to be considered an RTO. We did not order any modifications, but found that, for SPP to achieve RTO status, it would need to undertake such modifications. We have simply directed SPP to, among other things, file its Membership Agreement, pursuant to section 205 of the FPA, if it chooses to proceed in becoming an RTO. We have not required SPP to revise its current Membership Agreement in order to maintain status quo with the Commission.

24. Section 4.1.1 of the Membership Agreement refers to the withdrawal provisions for SPP members. Captioned “Withdrawal for Members,” section 4.1.1 provides guidelines for members to withdraw, specifically with respect to TOs, and states that “withdrawal shall not become effective until FERC has accepted the notice of withdrawal or otherwise allowed such withdrawal.”

25. A fundamental tenet of contract interpretation is that a contract provision should be interpreted, where possible, as consistent with the contract as a whole and that contract must be interpreted as a whole.34 Our ruling conforms to the generally accepted canons of contract interpretation; which require that: (1) a contract should be interpreted as an integrated whole; (2) provisions of a contract should normally not be interpreted as being in conflict; and (3) a more particular and specific clause of contract should prevail over a more general clause.35

26. Here section 4.1.1 refers to the withdrawal provisions for SPP members from SPP membership. Section 5.1.b refers only to specific circumstances that were applicable before the Commission first accepted the Membership Agreement. In light of this fact, there is no merit to arguments that our ruling is inconsistent with the express terms of the Membership Agreement.

27. Further, the Commission did not usurp state authority by interpreting the Membership Agreement it previously accepted in 1999. That agreement set forth the rights and obligations of the parties with respect to FERC-jurisdictional matters generally relating to transmission. No state contended that its terms provided the Commission with authority that was properly held by states, and we accepted it without modification. Section 4.1.1 of the Membership Agreement provides, inter alia, that a TO's withdrawal “shall not become effective until FERC has accepted the notice of withdrawal or otherwise allowed such withdrawal . . . .” Further, under section 8.12, members have agreed to be bound to amendments approved by the Board subject to rights to challenge any amendments at FERC and to exercise any withdrawal rights it possesses . . . .” In this proceeding, SPP has asked that we consider its request for RTO status in the context of its jurisdictional Membership Agreement, including proposed revisions thereto. Our

34 See generally Clyburn v. 1411 K St. Ltd. Partnership, 628 A.2d 1015, 1018 (D.C. 1993); BWX Elecs., Inc. v. Control Data Corp., 289 U.S. App. D.C. 114, 929 F.2d 707, 711 (D.C. Cir. 1991) (“It is a fundamental tenet of contract interpretation that a contract provision should be interpreted, where possible, as consistent with the contract as a whole.”).

35 See, e.g., Restatement (Second) of Contracts § 203(a), comment b (1979)(contract should be interpreted as a whole, with no part assumed to be superfluous); Brinderson-Newberg Joint Venture v. Pacific Erectors, Inc., 971 F.2d 272, 278-79 (9th Cir. 1992) (contract should be interpreted to give meaning to each of its provisions); Hawthorne Land Company v. U.S., 309 F.3d 888 (2002); Cruden v. Bank of New York, 957 F.2d 961, 976 (2d Cir. 1992) (“The entire contract must be considered, and all parts of it reconciled, if possible, in order to avoid an inconsistency.”).
consideration under such facts, of whether we should grant RTO status, relates to matters that are jurisdictional to the Commission and does not intrude upon any authority properly exercised by the states.

28. Furthermore, as we stated in our recent Guidance on Regional Transmission Organization and Independent System Operator Filing Requirements under the Federal Power Act, public utilities making section 205 filings will continue to be required to demonstrate that they meet the principles of Order No. 2000. In undertaking our review of such section 205 filings, the Commission will consider whether all of the elements contained in the filed arrangements meet the principles of Order No. 2000 and are just and reasonable pursuant to section 205 of the FPA. Further, our consideration will extend to matters such as whether, at the outset of an RTO, member entrance and exit rights are just, reasonable and not unduly discriminatory or preferential, as well as whether a specific proposed withdrawal of a participant is consistent with the FPA. Thus, it is essential that the Membership Agreement provide that no jurisdictional transmission owner may exit SPP without a Commission determination that it is just and reasonable for it to do so.

Joint and Common Market

February 10 Order

29. In the February 10 Order, the Commission found that SPP conditionally satisfied Order No. 2000’s scope requirement. We found that, with its present membership, SPP serves a multi-state region of sufficient size to maintain reliability, effectively perform its required functions, and support efficient, non-discriminatory power markets. Nevertheless, to address concerns about the adequacy of SPP’s scope, we required SPP to file a seams agreement with the Midwest ISO and participate in the Joint and Common Market with the Midwest ISO and PJM Interconnection, L.L.C. (PJM).  

Requests for Rehearing

30. AEP West states that SPP’s participation in a Joint and Common Market with the Midwest ISO and PJM will require full implementation of Phase 2 (including market-based congestion management with financial transmission rights) and Phase 3 (including

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36 104 FERC ¶ 61,248 at P 3 (2003).

37 February 10 Order at P 62.

38 Id. at P 64.
bid-based ancillary services markets) of SPP’s market development plan. However, according to AEP West, SPP will proceed with these stages only if a cost/benefit analysis demonstrates positive net benefits. AEP West seeks Commission clarification that SPP’s required participation in the Joint and Common Market should not depend upon implementation of Phases 2 and 3 of its market development plan.39

31. State Regulators argue that the Commission exceeded its authority in requiring SPP to participate in a Joint and Common Market with the Midwest ISO and PJM. They contend that this requirement is tantamount to ordering SPP utilities into an RTO that includes the Midwest ISO and PJM regions and preempts state review of such matters.40 They further contend that this requirement effectively commits SPP to adopt market systems and congestion management schemes that are compatible with those of the Midwest ISO and PJM, but which might not be appropriate for consumers in SPP’s footprint.41 Moreover, State Regulators maintain that there is no evidence that such participation would provide any net benefits to the customers of RTO members.42

Discussion

32. We will deny rehearing on issues concerning the Joint and Common Market with the Midwest ISO and PJM. SPP’s participation in the Joint and Common Market is necessary to alleviate balkanized transmission control and additional seams costs in the region. In response to AEP West’s concerns, we find that implementation of the Joint and Common Market is not dependent upon the implementation of Phases 2 and 3 of SPP’s market plan. As discussed herein, a cost/benefit analysis will be performed in Phase 2 to determine whether more market functions and the removal of barriers to entry are beneficial to SPP. If the cost/benefit analysis studies in Phase 2 markets find that

39 AEP West at 13-14.

40 They cite section 202(a) of the FPA as requiring the Commission to “afford each such State commission reasonable opportunity to present its views” and “to receive and consider such views and recommendations.” 16 U.S.C. § 824a(a).

41 For example, they argue that SPP could be required to adopt a Locational Marginal Pricing (LMP) energy market similar to that utilized by PJM, without a showing that LMP is an appropriate method of congestion management in the SPP region.

42 State Regulators at 2, 17-20.
there are no benefits to customers, SPP will perform in market (i.e. the Midwest ISO’s Day-2 market) to non-market (i.e., SPP’s current status without organized energy markets) posture in the Joint and Common Market.

33. With respect to the State Regulators arguments, we did not preempt state review in directing SPP to participate in the Joint and Common Market. As stated above, there will be a cost-benefit test prior to SPP’s decision to proceed to a further phase of market development. We expect the states to be actively involved in this analysis. Further, we emphasize that our orders in this proceeding set forth the standards with which SPP must comply in order to achieve RTO status, but we have not required SPP to become an RTO. SPP is voluntarily seeking RTO status, and as an RTO, SPP must participate in the Joint and Common Market with the Midwest ISO and PJM.43

Operational Authority

Consolidation of Control Areas

February 10 Order

34. In the February 10 Order, the Commission acknowledged concerns regarding SPP’s operation of multiple, i.e., 18 control areas. However, rather than ordering immediate consolidation, we directed SPP to study the feasibility of reducing the control areas within its footprint and provide the Commission with the outcome of its study, within one year of the February 10 Order.44

Request for Rehearing

35. On rehearing, TDU Intervenors express concern that the study will be unduly influenced by the SPP TOs that will be affected by consolidation of control areas. Accordingly, TDU Intervenors seek a Commission requirement that the study be conducted by an independent entity that answers directly to the Commission, rather than SPP.

36. In addition, TDU Intervenors state that the Commission should instruct SPP to require control-area operator TOs to abide by the same terms and conditions that affect other customers under the SPP RTO OATT.45

43 February 10 Order at P 63.

44 Id. at P 81.

45 TDU Intervenors at 4.
Discussion

37. We will deny rehearing on this issue. We are satisfied that SPP, with its independent Board, has sufficient independence to study the feasibility of reducing the control areas within its footprint. While we recognize that SPP TOs will be affected by consolidation and, thus, should have interest in the study, we expect that SPP’s comprehensive study should reflect input from other stakeholders, including TDU Intervenors. Moreover, the study will be filed, subject to notice and comment procedures, and will inform further Commission action in this regard.

38. We agree that TO control area operators should be subject to the same terms and conditions as other customers under SPP’s OATT. However, we will not require a specific amendment to SPP’s OATT at this time.

Short Term Reliability

February 10 Order

39. In the February 10 Order, the Commission found that SPP satisfied Order No. 2000 requirements for short-term reliability. We determined that SPP’s revised Bylaws, revised Membership Agreement, and OATT confirm that SPP will have exclusive authority for maintaining the short-term reliability of its operating grid. In response to the New Mexico Attorney General’s concerns about SPP serving as both the RTO and reliability organization, we stated that we would not require a separation at this time.  

Requests for Rehearing

40. On rehearing, Southwestern Public Service reiterates the New Mexico Attorney General’s concerns regarding SPP’s function as an RTO and reliability organization. Southwestern Public Service states that it will be difficult for SPP to argue for reliability over market protocols without having independently established standards for guidance.

46 We address the matter of SPP’s independent Board in our order addressing SPP’s compliance filing to the February 10 Order.

47 February 10 Order at P 89-91.

48 Southwestern Public Service at 1-2.
Discussion

41. We will deny rehearing. As stated in the February 10 Order, we will consider issues relevant to SPP performing dual functions as an RTO and reliability organization, but we will not require any separation.\textsuperscript{49} We note the recommendation of the U.S.-Canada Power System Outage Task Force Report, which stated, “FERC should not approve the operation of new RTOs or ISOs until they have met minimum functional requirements.”\textsuperscript{50} Southwestern Public Service presents no new arguments on rehearing that warrant reversal of the February 10 Order on this issue.

RTO Functions

Grandfathered Agreements and Bundled Retail Load

February 10 Order

42. In the February 10 Order, we recognized that treatment of grandfathered wholesale agreements (GFAs) and bundled retail load is a difficult issue with wide-ranging implications. We recognized that the issue impacts an RTO’s ability to effectively administer its tariff and operate markets. Accordingly, we encouraged transmission customers with GFAs to convert to direct service under the SPP OATT. However, we did not require such conversion or abrogate any contracts. Rather, consistent with Order No. 2000-A,\textsuperscript{51} we required that TOs, on behalf of their entire load, including grandfathered wholesale and bundled retail loads, take service under the non-rate terms and conditions in the SPP OATT as a prerequisite to obtaining RTO status from the Commission.\textsuperscript{52} We further required SPP to include in its compliance filing: (1) the magnitude of load that is proposed to be grandfathered wholesale, as well as bundled retail load, and to indicate what percentage of these loads will be to the total load served under SPP’s tariff; and (2) a schedule for converting its GFAs to the SPP OATT, consistent with the guidance provided to the Midwest ISO, to facilitate market operations.\textsuperscript{53}

\textsuperscript{49} February 10 Order at P 91.


\textsuperscript{51} Order No. 2000-A at 31,375-75.

\textsuperscript{52} February 10 Order at P 108.
Requests for Rehearing

43. On rehearing, State Regulators and KCPL raise jurisdictional concerns with the Commission’s directive that bundled retail load be subject to the non-rate terms and conditions of the SPP RTO OATT. State Regulators argue that, in all respects, bundled retail load falls under state jurisdiction. They maintain that the February 10 Order violates the FPA, judicial precedent, and Order No. 2000, all of which, they contend, preserve state authority over retail ratemaking issues, including rates, terms, and conditions. Moreover, according to State Regulators, there has been no factual showing that placing native load under the SPP RTO OATT is necessary to eliminate undue discrimination in the wholesale market. KCPL urges the Commission to address these jurisdictional issues.

44. On the other hand, the Oklahoma Commission applauds the Commission’s approach to the treatment of bundled retail load. The Oklahoma Commission contends that the February 10 Order provides a framework for a balanced approach to the formation of the SPP RTO and that, through other policies, the Commission has provided assurance that state authority over bundled retail transmission service is protected.

45. AEP West seeks several adjustments to the Commission’s treatment of GFAs. AEP West argues that any incremental costs associated with RTO participation should be borne by customers under the GFAs, not the TOs or their native load customers. AEP West argues that it would be unfair and discriminatory for the Commission to require TOs to bear all administrative costs under the OATT, including costs attributable to loads served under GFAs. In addition, while the Commission required SPP to provide a schedule for converting GFAs to OATT service, AEP West states that long-term GFAs should be converted within a reasonable time frame.

46. East Texas Cooperatives state that the Commission should clarify what it means by “non-rate terms and conditions.” They argue that certain tariff provisions could be interpreted as having both rate and non-rate elements. More specifically, East Texas Cooperatives want the energy imbalance market to be considered a non-rate provision in the SPP OATT, to which all load in SPP will be subject. They also seek clarification concerning which rate-related tariff provisions TOs will be exempt from with respect to their grandfathered wholesale and bundled retail loads.

53 Id. at P 110.
Discussion

47. With respect to claims that the Commission exceeded its authority, the February 10 Order does not disturb state authority over retail ratemaking matters. The February 10 Order required that the TOs take service under the non-rate terms and conditions of SPP RTO’s OATT on behalf of its bundled retail load (and grandfathered wholesale load) to meet the Order No. 2000 requirement that SPP, as an RTO, be the sole provider of transmission service. The February 10 Order encouraged customers with GFAs to convert to direct service under the SPP OATT and required that SPP provide information regarding the magnitude of grandfathered and bundled retail load but preserved the rates, terms and conditions of GFAs. The Commission did not explicitly address the specific rates, terms and conditions of bundled retail service arrangements.

48. With respect to AEP West’s arguments, we believe, as provided in Opinion No. 453, and related orders, that all load should be assessed SPP RTO operating costs. With respect to GFAs, AEP West and other TOs may seek recovery of such costs that it is assessed for GFA load, to the extent permitted under the respective GFAs. Moreover, AEP West and other TOs may file with their respective states to seek recovery of SPP RTO operating costs assessed to bundled retail load.

49. Regarding East Texas Cooperative’s specific request that the energy imbalance market be considered a non-rate provision, we will not impose that specific requirement at this time. The Commission will consider this issue in the context of its review of SPP’s filing to implement its energy imbalance market.

Compensation for Customer-Owned Transmission Facilities

February 10 Order

50. In the February 10 Order, the Commission addressed concerns regarding the inclusion of more than one TO’s facilities under SPP’s control within a single transmission-pricing zone, as well as distribution of revenues by SPP to such TOs. We recognized that SPP’s resolution of these issues will take time. We referred parties to

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54 February 10 Order at P 108.

55 In this regard, we expect SPP to file its energy imbalance market proposal well in advance of the minimum 60 day notice requirement in order to provide sufficient time for review and consideration. This additional time will help avoid a delay in the imbalance market implementation if changes to its proposal are required.
relevant Commission precedent, including *Wolverine*.\(^{56}\) We further directed SPP to submit a timetable for resolving such concerns.

**Requests for Rehearing**

51. On rehearing, East Texas Cooperatives urge the Commission to adopt a single definition of transmission and an equitable methodology for allocating transmission revenues among multiple TOs located in a single pricing zone. They contend that the Midwest ISO Agreement provides an effective mechanism for allowing multiple owners in a transmission zone to agree upon an equitable distribution of zonal revenues\(^{57}\) and that a similar mechanism is needed in the SPP OATT or revised Membership Agreement.

**Discussion**

52. We will deny East Texas Cooperatives’ rehearing request on this issue. We note that East Texas Cooperatives acknowledge that SPP stakeholders are currently in the process of developing a single definition of transmission and an equitable revenue distribution methodology. As we stated in the February 10 Order, resolution of these issues will take time. Therefore, we will not interrupt SPP’s process.

53. However, as we note in our order addressing SPP’s compliance filing to the February 10 Order, SPP failed to submit a timetable for resolving issues regarding, among other things, inclusion of more than one TO’s facilities under SPP’s control within a single transmission-pricing zone, as well as distribution of revenues by SPP to such TOs. In that order, we redirect SPP to submit the timetable, including a timeframe for resolving the concerns regarding compensation for customer-owned transmission facilities.

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\(^{56}\) Midwest Independent Transmission System Operator, Inc., 101 FERC ¶ 61,004 at 61,010 (2002), *reh’g pending*. In that case, we stated that participation of new TOs in RTOs would be accommodated by providing appropriate compensation for their transmission facilities, whether by establishing such entities as separate pricing zones or incorporating such entities into existing pricing zones.

\(^{57}\) They cite Midwest ISO Agreement, Appendix C, Section III.A.
Congestion Management

February 10 Order

54. In the February 10 Order, the Commission emphasized Order No. 2000’s requirement that an RTO ensure the development and operation of market mechanisms to manage transmission congestion.\(^5\) In accordance with Order No. 2000, we accepted SPP’s proposed congestion management methodology as a reasonable, Day 1 approach for managing congestion.\(^5\) We further accepted SPP’s commitment for phased implementation of its energy imbalance market.\(^6\) We stated that SPP’s phased-in congestion management proposal is a work in progress, which we will fully address when the completed proposal is filed under section 205 of the FPA. We strongly urged SPP to resolve issues raised by parties, after the independent Board of Directors is in place. We stated that, if substantial issues remain, we will institute procedures to resolve them.\(^6\)

Requests for Rehearing

55. On rehearing, AEP West seeks Commission clarification that funding and implementation of Phases 2 and 3 of SPP’s market development plan must be supported by a positive demonstration of net benefits. AEP West contends that the Arkansas and Missouri Commissions will not allow utilities in their states to recover the costs of any RTO program or participation unless the utilities receive state approvals, after proving the need for and cost-effectiveness of such a program.

56. The New Mexico Attorney General argues that, to the extent the February 10 Order requires market-based rates, the order violates the FPA’s requirement that every utility charge a filed rate. The New Mexico Attorney General specifically cites the

\(^{5}\) February 10 Order at P 133 (citing Order No. 2000 at 31,126).

\(^{5}\) As detailed in the February 10 Order at P 116, SPP manages congestion using a market mechanism involving generation redispatch. SPP stated that it receives price quotes from generators that can relieve a constraint and chooses a variety of economic alternatives to customers. SPP uses this mechanism, along with a transmission loading relief process and discounting, to encourage counterflows to relieve congestion.

\(^{6}\) See Order No. 2000 at 31,126.

\(^{6}\) February 10 Order at P 134.
Commission’s discussion of SPP’s congestion management scheme as apparently
directing market-based rates. The New Mexico Attorney General states that market-
based rates are neither definite nor capable of being calculated, as the FPA requires.

57. Golden Spread seeks Commission clarification that SPP may not implement
market-based congestion management unless and until SPP’s market monitor
recommends, and the Commission finds, that the SPP region has adequate transmission
infrastructure and sufficiently competitive wholesale generation markets. Otherwise,
according to Golden Spread, the use of market-based congestion management
mechanisms is likely to increase the ability of generators with local market power to
exercise that power, to the detriment of load-serving entities, such as Golden Spread.
Golden Spread argues that the result of a cost/benefit analysis prior to implementation of
market-based congestion management cannot alone justify implementation of such a
mechanism.

58. Golden Spread further argues that the Commission unlawfully delegated to the SPP
Board of Directors its responsibility to ensure just and reasonable rates, by advising SPP
to resolve issues concerning congestion management.

Discussion

59. We clarify that the February 10 Order does not contemplate any development and
implementation of Day 2 markets, beyond the energy imbalance market in development
as part of Phase 1 of SPP’s plan, without the preparation of cost/benefit analysis. In its
initial application, SPP stated that it would not pursue market development, beyond its
planned Phase 1 energy imbalance market, without first performing cost/benefit analyses,
following its establishment of high-level designs for Phase 2 (Financial Transmission
Rights (FTRs) for LMP) and Phase 3 (ancillary services), respectively.

60. The February 10 Order made no specific finding with regard to SPP’s plan to
perform cost/benefit analyses for Phases 2 and 3 of its market development. However,
the February 10 Order provided “[w]e will accept SPP’s proposed congestion
management methodology as a reasonable initial approach to managing congestion.
Moreover, we will accept SPP’s commitment for phased implementation of its energy
imbalance market. SPP’s Day 2 congestion management plan will be addressed when the
completed proposal is filed under Section 205 of the FPA.” In doing so, the February 10
Order also provided that “[c]onsistent with Order No. 2000, once the new independent
Board of Directors is in place, we strongly urge SPP to resolve issues raised by
intervenors in their Members Committee process.” We directed the Independent Market
Monitor (IMM) to perform analyses to support SPP’s efforts in reviewing costs and

62 Golden Spread at 14.
benefits of developing market functions and removing barriers to entry. We also required
the IMM to submit a report to the Commission assessing the efficiency of current
redispacth procedures in time to be considered when evaluating SPP’s Phase 2 market
design.

61. We find the New Mexico Attorney General’s concerns to be premature. The
February 10 Order did not direct market-based rates or address the rates to be charged in
bilateral markets for energy, capacity or ancillary services in SPP’s footprint. SPP must
file tariff revisions to implement its Day-2 market. SPP has not done so. If SPP makes
such a filing in the future, then the New Mexico Attorney General may raise its concerns
at that time. Further, to the extent SPP adopts them, sellers in SPP-administered
markets will, if necessary, require market based rate authorization. To the extent that the
New Mexico Attorney General disputes market-based rates in general, we find such
arguments to be beyond the scope of this proceeding.

62. We disagree with Golden Spread that the Commission unlawfully delegated
responsibility for ensuring just and reasonable rates to the SPP Board of Directors. This
Commission will, pursuant to the FPA, review any SPP filing relating to congestion
management systems. Regarding Golden Spread’s request that SPP not be allowed to
implement market-based congestion management until the Commission finds SPP region
has adequate transmission and competitive wholesale markets, we will address this
further at the time SPP’s Phase 2 design is presented and its regional transmission plan is
closer to being finalized.

Market Monitoring

February 10 Order

63. In the February 10 Order, we required SPP to have an IMM in place to oversee the
reliable operation of the transmission system, as a prerequisite to obtaining RTO status
from the Commission. We directed SPP to provide a market monitoring plan no later
than 60 days prior to implementing Phase 3 of its energy imbalance market. We stated
that this plan should include appropriate market power mitigation measures to address
market power problems in the spot markets and a clear set of rules governing market
participant conduct, with the consequences for violations clearly spelled out. We also
stated that the plan should include the process that the IMM will use if the IMM finds
that the markets are not providing appropriate incentives for investment in needed
infrastructure. We also directed SPP’s market monitoring plan to include periodic reports
prepared by the IMM. We directed these reports to incorporate market metrics to provide
a basis for measuring performance of these markets across RTOs and ISOs, and to compare the performance of the market in each RTO or ISO over time. We stated that metrics will also be developed to provide standard performance information on a monthly basis.63

Requests for Rehearing

64. On rehearing, TDU Intervenors seek Commission clarification that SPP’s market monitoring plan should cover bilateral markets, in addition to spot markets. If the Commission intended to exclude bilateral markets, then they seek rehearing on that issue. TDU Intervenors state that the SPP region especially demands monitoring of bilateral contracts, because, according to TDU intervenors, bilateral contracts are, and will likely remain, the dominant means of energy trading.

65. Golden Spread argues that the Commission erred by failing to give the IMM adequate enforcement power. Specifically, Golden Spread states that the IMM should have the enforcement power to evaluate the sufficiency of the SPP region’s infrastructure and the status of the region’s wholesale power markets. Golden Spread also emphasizes that protestors should have an opportunity to comment on SPP’s proposed market monitoring plan.

66. Golden Spread and TDU Intervenors argue that the Commission’s decision to allow SPP to file its market monitoring plan just prior to implementing Phase 3 of its market development plan is problematic. Golden Spread maintains that SPP’s timeline has already begun to slip and that SPP may never reach Phase 3, if its cost/benefit analysis shows that the costs outweigh the benefits. Accordingly, Golden Spread envisions a scenario in which SPP has RTO authority but never decides to move past Phase 1 or Phase 2 of its market development plan. On that point, TDU Intervenors seek Commission clarification that its requirement that SPP’s market monitoring plan include energy markets applies to the Phase 1 energy imbalance implementation date.

Discussion

67. We reject as premature arguments that SPP’s market monitoring plan should include bilateral markets. SPP has not yet filed its market monitoring plan, so we will not address at this time the issue of whether its plan must include bilateral markets. When SPP files its market monitoring plan, it will be noticed and interested parties will be given an opportunity to comment. We note that, while a market monitor’s fundamental responsibility is to monitor the RTO-enabled and administered markets, in Order No. 2000, we found that an RTO must periodically assess how behavior in markets operated

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63 February 10 Order at P 173.
by others (e.g., bilateral power sales markets and power markets operated by unaffiliated power exchanges) affects RTO operations, and conversely, how RTO operations affect the performance of power markets operated by others.\textsuperscript{64} Pursuant to Order No. 2000, in carrying out its market monitoring function, SPP must satisfy this standard, or demonstrate that an alternative proposal is consistent with, or superior to, it.\textsuperscript{65}

68. We further reject as premature arguments regarding the scope of the IMM’s enforcement powers. These arguments can be raised when SPP files its market monitoring plan. However, again we emphasize that the role of SPP’s IMM, and its ability to impose sanctions must be consistent with Commission orders on market behavior rules.\textsuperscript{66}

69. We will grant rehearing on the issue of when SPP must file its market monitoring plan, and provide clarification as follows. In the February 10 Order, we indicated that SPP must file its market monitoring plan no later than 60 days prior to Phase 3 of its market implementation plan.\textsuperscript{67} In fact, our intent was that SPP file its plan no later than 60 days prior to implementing the third increment of Phase 1, which is to include the offer-based energy imbalance market, along with market monitoring and market power mitigation. Accordingly, we will direct SPP to file its market monitoring plan at least 60 days prior to implementing increment 3 of Phase 1 (the energy imbalance market), which we understand is targeted for November 2005. SPP’s market monitoring plan will be noticed and interested parties will have an opportunity to comment.

**Planning and Expansion**

**February 10 Order**

70. In the February 10 Order, the Commission commended SPP for its efforts in updating its transmission planning and expansion process. We noted that SPP is currently reviewing this function, with an eye toward making the process more open and

\textsuperscript{64} Order No. 2000 at 31,146.

\textsuperscript{65} Id.

\textsuperscript{66} See Investigations of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC ¶ 61,218 (2003), order on rehearing, 107 FERC ¶ 61,175 (2004). In addition, the Commission expects to issue a forthcoming policy statement regarding the role of market monitors.

\textsuperscript{67} February 10 Order at P 173.
participatory, and is evaluating a two-year planning cycle, with the first year’s focus on reliability, and the second year’s focus on market needs.\textsuperscript{68} We also found promising SPP’s ongoing efforts to accommodate third-party investment and participation in transmission upgrade projects.\textsuperscript{69} To that end, we required SPP to file specified milestones to ensure that it meets its planning cycle.\textsuperscript{70}

71. We also found that Attachment O of SPP’s OATT\textsuperscript{71} failed to provide SPP with the authority to independently oversee the regional transmission plan and solely determine the priority of transmission planning projects that address reliability and economic needs.\textsuperscript{72} We stated that TOs may perform studies and evaluate changes to their transmission systems; however, SPP should provide independent oversight of these studies to ensure that any proposed changes will not impede SPP’s ability to provide efficient, reliable, and non-discriminatory transmission service. Accordingly, we directed SPP to file changes to Attachment O of its OATT to reflect SPP’s authority to plan transmission and to make it consistent with provisions of the revised Membership Agreement, which address SPP’s and the TOs’ role in the transmission planning process.\textsuperscript{73}

72. We further required SPP to develop and file a transmission cost allocation plan by the end of 2004, addressing pricing treatment for the projects identified in SPP’s transmission plan. Regarding generator interconnector proposal, we directed SPP to follow compliance procedures in Docket No. RM02-1-000, Standardization of Generator Interconnection Agreements and Procedures.\textsuperscript{74} We noted that compliance with those

\textsuperscript{68}Id. at P 185.

\textsuperscript{69}Id. at P 186.

\textsuperscript{70}Id. at P 187.

\textsuperscript{71}Attachment O sets forth SPP’s transmission planning and expansion procedures.

\textsuperscript{72}February 10 Order at P 188.

\textsuperscript{73}Id.

procedures will be handled in that case, and our acceptance of SPP’s proposal here is subject to the outcome of that proceeding.\textsuperscript{75}

\textbf{Requests for Rehearing}

73. State Regulators raise jurisdictional concerns regarding the Commission’s determination on planning and expansion issues. They maintain that the states have jurisdiction over planning and reliability, and that the Commission exceeded its authority by finding that SPP must solely determine the priority of transmission planning projects that address reliability and economic needs. They argue that the Commission has no legal authority over planning and reliability for bundled retail load.

74. State Regulators further argue that Order No. 2003 requirements should not be imposed on SPP. They contend that the costs of interconnection and transmission upgrades should be paid by the parties causing those costs to be incurred. On that point, Golden Spread further contends that SPP should be prohibited from using participant funding to pay for transmission system upgrades and expansions.

75. Golden Spread also claims that the February 10 Order fails to satisfactorily address transmission planning and expansion issues. Golden Spread states that the Commission’s determination on this issue will do nothing to address what Golden Spread considers to be the central problem, i.e., incumbent TOs, who have the right of eminent domain and therefore ability to build, often benefit financially from maintaining congestion, rather than relieving it.\textsuperscript{76} Therefore, Golden Spread argues that SPP’s Membership Agreement should be revised to explicitly state that SPP must independently perform all necessary facilities studies for the transmission system, and that SPP has the authority to impose substantial sanctions upon any transmission owner that fails to use best efforts to construct or arrange for the construction of any transmission expansion, addition or upgrade approved by the RTO planning process. Similarly, TDU Intervenors argue that TOs must have an enforceable obligation to build, and that SPP should be required to timely alert the Commission of a TO’s refusal to build.

76. In addition, TDU Intervenors argue that the Commission’s directive that SPP modify its Attachment O to make it consistent with the revised Membership Agreement is inadequate, because, according to TDU Intervenors, section 2.1.5 of that agreement simply refers back to the planning criteria contained in section 1.0 of Attachment O, and

\textsuperscript{75} February 10 Order at P 189.

\textsuperscript{76} Golden Spread at 5.
that section allows TOs to develop their own transmission planning criteria.\footnote{TDU Intervenors contend that those criteria state, among other things, that the individual planning criteria of each TO shall be the basis for determining whether a violation of criteria exists and when a need for new facilities should be considered.} TDU Intervenors further seek Commission clarification that the SPP RTO must be more than a collector and assembler of information.

77. TDU Intervenors also state that planning and expansion must encompass economic as well as reliability upgrades.\footnote{They argue that the Commission’s directive that SPP plan efficient transmission service is inadequate. \textit{See} February 10 Order at P 181 n.229.} In addition, TDU Intervenors argue that the Commission should clarify that all entities, whether investor-owned, government-owned, or consumer-owned, must have a clear right to participate as transmission-owning members of the SPP RTO. They further state that the Commission should require SPP to adopt language in its revised Membership Agreement that is consistent with language utilized by the Midwest ISO, which provides that “Third-parties shall be permitted and are encouraged to participate in the financing, construction and ownership of new transmission facilities as specified in the Midwest ISO Plan.”\footnote{TDU Intervenors cite Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, First Revised Sheet No. 112.}

**Discussion**

78. We will deny rehearing requests on this issue. SPP’s responsibilities as an RTO in developing a regional transmission plan do not infringe on matters within state jurisdiction, such as siting and certification of new transmission facilities. SPP’s RTO responsibilities in this area should be exercised in coordination with the participation and input of states, the SPP RSC, and interested parties.

79. In response to TDU Intervenors’ concerns, we do not intend that the SPP RTO merely collect and assemble information. As provided in the February 10 Order, SPP has independent responsibility to develop a regional transmission plan, taking into account reliability and economic needs.

80. With respect to Golden Spread's concerns, we believe SPP, under its independent Board, will exercise sufficient oversight over transmission planning and construction activities to assure a cost effective transmission expansion plan that addresses reliability
and economic needs. Moreover, as stated in Order No. 2000,80 “nothing in th[at] Rule relieves any public utility of its existing obligation under the pro forma transmission tariff to expand or upgrade its transmission system upon request.” We reiterate this principle here.

81. With respect to concerns about TOs’ transmission planning criteria, we will deny rehearing. While section 1.0 of Attachment O allows TOs to develop their own transmission planning criteria, that criteria “shall, at a minimum, conform to SPP Criteria and NERC Planning Standards.”81 We find that this provision does not infringe upon SPP’s role in the transmission planning process.

Other Issues

Regional State Committees

February 10 Order

82. In the February Order, the Commission stated that it fully supported the creation of a Regional State Committee (RSC) within the SPP footprint.82 We stated that a representative RSC will benefit SPP and market participants by instituting a partnership between this Commission and state commissions, through which regional issues can be addressed. However, we found that the SPP’s and Supporting Commission’s83 proposal concerning RSCs did not adequately address several important issues.

83. We stated that the RSC should have primary responsibility for determining regional proposals and the transition process in the following areas: (1) whether and to what extent participant funding would be used for transmission enhancements; (2) whether license plate or postage stamp rates will be used for the regional access charge; (3) FTR allocation where a locational price methodology is used; and (4) the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to

80 Order No. 2000 at 31,164.

81 See SPP OATT Fourth Revised Volume No. 1, First Revised Sheet No. 183.

82 February 10 Order at P 218.

83 The Supporting Commissions included the Arkansas, Missouri and Oklahoma Commissions.
the customers’ existing firm rights. We stated that, if the RSC reaches a decision on the methodology that should be used, SPP would file this methodology pursuant to section 205 of the FPA, and that SPP can also file its own proposal under section 205.84

84. The Commission further stated that the RSC should determine the approach for resource adequacy across the entire region, and that, with respect to transmission planning, the RSC should determine whether transmission upgrades for remote resources will be included in the regional transmission planning process, as well as the role of TOs in proposing transmission upgrades in the regional planning process.85

Requests for Rehearing

85. On rehearing, State Regulators argue that state participation in the RSC is voluntary, and that the RSC itself cannot limit or usurp state authority. They assert that the states have jurisdiction over transmission planning, bundled native load customers, and reliability issues. They further assert that, to the extent participating states have approved of an RSC decision on these and other asserted state-jurisdictional issues, neither SPP nor the Commission may override that RSC decision.

86. On rehearing, the Kansas Commission and Golden Spread argue that the Commission unlawfully delegated its responsibilities under the FPA to the RSC, by giving the RSC decision-making authority over whether and to what extent participant funding would be used for transmission enhancements, whether transmission upgrades for remote resources will be included in the regional transmission planning process, and the approach for resource adequacy across the SPP region. The Kansas Commission and Golden Spread argue that the RSC should assume the role of an advisory body to the independent SPP Board of Directors. The Kansas Commission seeks Commission clarification that any RSC initiatives are subject to Commission review and that the RSC is accountable to both SPP and the Commission.

87. To that end, the Kansas Commission further argues that the Commission failed to provide guidance regarding the appropriate relationship between the RSC and SPP Board of Directors, or regarding the preferred voting structure of the RSC. Accordingly, the Kansas Commission argues that the Commission failed to ensure proper independence of the SPP Board of Directors, given that members of the RSC have a strong vested interest in the outcome of SPP’s energy markets.

84 February 10 Order at P 219.

85 Id. at P 220.
88. In addition, the Kansas Commission argues that the February 10 Order erroneously allows the RSC to compel SPP to make a section 205 filing. The Kansas Commission contends that the RSC should not have the “primary” responsibilities indicated in the February 10 Order and that the Commission should have directed a hearing regarding the RSC’s role.

89. TDU Intervenors argue that the Commission failed to require municipal and cooperative representation on the RSC. They state that the RSC should not be limited to state commissions and that the Commission must ensure that the RSC will represent the interests of all customers in the SPP region.

**Discussion**

90. We will clarify the issues concerning the RSC. As set forth above, the Commission has addressed issues concerning transmission planning, bundled retail load and reliability in a manner consistent with its jurisdiction. Moreover, we emphasize that, our purpose in approving an RSC is not to usurp state authority, but, rather, to facilitate state consensus on certain regional issues and a partnership between this Commission and state commissions.  

91. With regard to arguments that we unlawfully delegated to the RSC our responsibilities under the FPA to determine just and reasonable rates, terms and conditions, we emphasize that, like any proposal filed pursuant to section 205, proposals filed at the behest of the RSC are subject to Commission review and disposition.

92. We further dismiss as moot arguments that the February 10 Order erroneously allows the RSC to compel SPP to make a section 205 filing. We emphasize that SPP voluntarily filed the RTO application at issue in this proceeding. In acting on that application in the February 10 Order, we required SPP to allow the RSC to direct certain section 205 filings. By deciding to proceed with its RTO application, SPP has voluntarily agreed to file with the Commission, pursuant to section 205, certain regional proposals that may be developed by the RSC. Because SPP has so agreed, the February 10 Order language on this issue no longer governs. Accordingly, since the factual predicate upon which these rehearing arguments were based no longer exists, we dismiss these arguments as moot.

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86 According to SPP’s website, the RSC is comprised of retail regulatory commissioners from agencies in Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma and Texas. See [http://www.spp.org/Committee_Results.cfm?PassObj=1568](http://www.spp.org/Committee_Results.cfm?PassObj=1568) (visited Aug. 13, 2004).
93. We reject arguments that the RSC is infringing on SPP’s own section 205 filing rights. As noted above, SPP agreed to file with the Commission certain regional proposals that may be developed by the RSC. In addition to RSC proposals, SPP may file its own proposals. Moreover, in our order on SPP’s compliance filing to the February 10 Order, we accepted proposed language in section 7.2 of SPP’s Bylaws, which provides that no RSC proposal “shall prohibit SPP from filing its own related proposal(s) pursuant to [s]ection 205.”

94. With regard to arguments that the RSC should be advisory only, we find that no new arguments were raised on rehearing that were not addressed and rejected in the February 10 Order. In any case, we emphasize that the RSC has primary, but not sole, responsibility for determining the proposals indicated in the February 10 Order, to the extent that SPP also can file its own proposals.

95. Finally, while TDU Intervenors argue that the Commission must ensure municipal and cooperative representation on the RSC, we disagree. The RSC is an organization of state regulators with jurisdiction over utilities in their respective states. The RSC is designed to give a voice to the state regulators of the utilities they regulate. In some states, states regulate municipalities and cooperatives. To the extent municipalities and cooperatives are regulated by the state, membership of the municipalities and cooperatives themselves on the RSC conflicts with the goals and composition of the RSC. Further, to the extent municipalities and cooperatives are not regulated by the state, they are nevertheless represented in the SPP stakeholder process. In addition, the requirement requested by TDU Intervenors could result in the unbalanced representation of several municipalities or cooperatives from one state. We believe that state commissions are well-suited to coordinate and represent the interests of their respective states, as a whole, including the interests of the municipalities and cooperatives. Municipalities and cooperatives may also raise their concerns directly with this Commission.

Operating Budget

February 10 Order

96. In the February 10 Order, the Commission directed SPP to file its operating budget, for informational purposes, within 90 days of the date that SPP obtains operational authority over transmission facilities within its footprint.\footnote{Id. at P 46 (citing Ameren Services, et al., 103 FERC ¶ 61,178 at P 33 (2003) (Ameren), clarification granted, 104 FERC ¶ 61,097 (2003), reh’g denied, 105 FERC ¶ 61,018 (2003)).}
Requests for Clarification

97. TDU Intervenors request clarification that, consistent with *Ameren*, and in order to ensure accountability, the Commission should require SPP to file its operating budget on an annual basis, in addition to 90 days after it obtains operational authority. In addition, TDU Intervenors request clarification that SPP must, as in *Ameren*, “consult with stakeholders before making its Section 205 filing with the Commission.”

Discussion

98. We will grant TDU Intervenors rehearing request with regard to SPP’s filing its operating budget. In *Ameren*, the Commission required that the Midwest ISO file its actual and projected annual operating budget on an annual basis for Commission review. In addition, the Commission directed the Midwest ISO to consult with stakeholders prior to filing its annual operating budget. Consistent with *Ameren*, SPP is required to file on an annual basis its operating budget, in addition to filing its operating budget within 90 days of the date that it obtains operational authority over transmission facilities with its footprint. SPP is also directed to consult with stakeholders prior to making its informational filing with the Commission.

Schedule 1 Rate Pancaking

February 10 Order

99. In the February 10 Order, the Commission directed SPP to discuss with parties the issue of Schedule 1 rate pancaking and file a report, within one year, regarding its progress in resolving that issue.

Requests for Rehearing

100. On rehearing, TDU Intervenors contend the February 10 Order implicitly allowed rate pancaking under Schedule 1 to continue. They argue that allowing rate pancaking

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88 *See Ameren* at P 33. *See also* 104 FERC ¶ 61,097 at fn.12 (noting that annual budget filings during the transition period should be informational in nature rather than section 205 filings).

89 February 10 Order at P 156.

90 Schedule 1 provides for collection of two scheduling charges for transactions that source and sink in separate control areas.
to continue is inconsistent with Commission precedent.\textsuperscript{91} They state that SPP should be required to develop and file a postage-stamp scheduling rate, similar to that employed by the Midwest ISO, to replace the pancaked scheduling charges under Schedule 1.

101. TDU Intervenors also request that the Commission require SPP, in its compliance filing, to clarify that its total system load will be used as the denominator for determining the administrative costs component of Schedule 1.\textsuperscript{92}

**Discussion**

102. We will grant TDU Intervenors’ requests for rehearing. In Order No. 2000 the Commission required that an “RTO tariff must not result in transmission customers paying multiple access charges to recover capital costs.”\textsuperscript{93} The Commission also stated that “it is appropriate to allow RTOs to propose the use of license plate rates for a fixed term of the RTO’s choosing.”\textsuperscript{94} Moreover, in *Southwest Power Pool*,\textsuperscript{95} the Commission accepted SPP’s use of zonal rates. The Commission stated that by charging a zonal rate, SPP was voluntarily eliminating rate pancaking in order to address state concerns regarding costs shifts. However, the Commission warned SPP that although it was not seeking Independent System Operator (ISO) or RTO approval at that particular time, upon such approval in the future, SPP would be required to comply with any applicable requirements for single-system rates.\textsuperscript{96}

103. Consistent with Order No. 2000, we will require that SPP submit, within 90 days of the date of this order, a timetable detailing the timeframe required by SPP to remove pancaking from Schedule 1.


\textsuperscript{92} TDU Intervenors state that another component of Schedule 1 recovers the scheduling costs incurred by the SPP TOs (not SPP itself).

\textsuperscript{93} Order No. 2000 at ¶ 31,174.

\textsuperscript{94} *Id.* at ¶ 31,177.

\textsuperscript{95} *Southwest Power Pool, Inc.*, 89 FERC ¶ 61,284 at 61,889 (1999) (*Southwest Power Pool*).

\textsuperscript{96} *Id.*
104. With respect to TDU Intervenors’ concern regarding system loads, we agree that all system loads, including grandfathered wholesale and bundled retail loads, must be included in the denominator for deriving a charge for Schedule 1 administrative costs. Therefore, we will require that SPP have in place upon Commission approval as an RTO, a revised Schedule 1 specifying the inclusion of all system loads (i.e., including grandfathered wholesale and bundled retail loads).

Granularity of SPP’s Transmission Service

Request for Rehearing

105. TDU Intervenors maintain that the model used by SPP to sell transmission service is more granular, i.e., more refined, than the one used to implement Transmission Loading Relief (TLR). Because of this granularity difference, TDU Intervenors contend that SPP’s transmission service model allows SPP to sell more transmission service than the TLR model results indicate the transmission system can accommodate. This means, according to TDU Intervenors, that SPP sells more transmission service than its TLR model will allow SPP to continue when TLRs are called. TDU Intervenors state that this practice is especially costly to customers under the SPP OATT, who are unable to successfully redispactch their transactions to avoid punitive energy imbalance charges. TDU Intervenors argue that the Commission must require SPP to address these granularity issues.

Discussion

106. We will deny rehearing. We will examine TDU Intervenors’ concern in this regard in our order on SPP’s compliance filing to the February 10 Order, in our discussion of available transmission capacity calculations.

“And” Pricing

February 10 Order

107. As indicated above, in the February 10 Order, the Commission required SPP to develop and file a transmission cost allocation plan by the end of 2004. We stated that this plan should address pricing treatment for the projects identified in SPP’s transmission plan.  

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97 TDU Intervenors at 11-12.

98 February 10 Order at P 189.
Request for Rehearing

108. TDU Intervenors do not seek rehearing of the Commission’s approach here. However, they argue that it is SPP’s policy that if a network customer’s proposed use of a network resource requires network upgrades on a system other than the zone in which the customer’s network load is located, the network customer will be directly assigned the costs of the upgrade in addition to zonal network charges. TDU Intervenors state that the Commission must require SPP to eliminate its “and” pricing policy for network upgrades.

Discussion

109. We will deny rehearing on this issue. We find that TDU Intervenors’ argument is inconsistent with what SPP currently has on file with the Commission. Section 2 (Network Upgrades) of Attachment J (Recovery of Costs Associated with New Facilities) under the SPP Tariff provides that during the Transition Period:

The Transmission Customer(s) requesting Transmission Service which requires Network Upgrades shall pay the costs associated with those Network Upgrades to the extent consistent with Commission policy. Such costs shall be specified in a Service Agreement to be filed with the Commission.

110. Moreover, section 2 of Attachment J provides that after the Transition Period:

All Network Upgrades constructed for service under this Tariff shall be rolled-in with all other transmission facilities. There shall be no direct assignment of Network Upgrade costs to Transmission Customers. However, the Transmission Provider shall not allow the construction and roll-in of a Network Upgrade when the Transmission Provider finds more economic or efficient alternatives. This roll-in of Network Upgrades costs shall not include the portion of any such Network Upgrades paid for during the Transition Period through direct assignment to Transmission Customer(s).

99 TDU Intervenors note that this policy is expressly stated in a November 4, 2003 study proposed by the SPP Queue Improvement Task Force

100 Transition Period is defined in the SPP Tariff as the period from the Effective Date of this Tariff for the provision of Network Integration Transmission Service (February 1, 2000) to the last day of the fifth year thereafter.
111. We find that no “and” pricing is required by these provisions. Moreover, these provisions appear to be consistent with the Commission’s pricing policy. With regard to TDU Intervenors reference to a November 4, 2003 Queue Improvement Task Force proposal, that proposal has yet to be filed with this Commission.

**Independent Transmission Company Agreements**

**Request for Rehearing**

112. Golden Spread argues that SPP’s proposed Independent Transmission Company (ITC) Agreement\(^1\) has the potential to allow an ITC to interfere with the ability of the SPP to perform its required RTO functions. Golden Spread seeks a Commission requirement that the ITC Agreement be amended to state that, in all cases in which a dispute arises between SPP and the ITC, the SPP’s position shall prevail pending dispute resolution procedures.

**Discussion**

113. We will deny Golden Spread’s rehearing request on this issue. Golden Spread’s argument regarding ITC Agreements is premature. We did not accept for filing an ITC Agreement in the February 10 Order. We will review ITC Agreements on a case-by-case basis if and when they are filed individually under section 205 of the FPA.

The Commission orders:

(A) The requests for rehearing are hereby granted in part, and denied in part, as discussed in the body of this order.

(B) Except as provided in ordering paragraph (C) below, SPP is hereby directed to submit a compliance filing, within 30 days of the date of this order, as discussed in the body of this order.

(C) SPP is hereby directed to submit, with 90 days of the date of this order, a timetable detailing the timeframe required by SPP to remove pancaking from Schedule 1.

By the Commission.

(SEAL)

Linda Mitry,
Acting Secretary.

\(^{101}\)See Exhibit SPP-7 to RTO proposal.
Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, Joseph T. Kelliher,
and Suedeen G. Kelly.

Southwest Power Pool, Inc. Docket Nos. RT04-1-002
ER04-48-002

ORDER ON COMPLIANCE FILING

(Issued July 2, 2004)

1. In this order, the Commission addresses the compliance filing submitted by Southwest Power Pool, Inc. (SPP), pursuant to the Commission’s order issued in this proceeding on February 10, 2004.1 In the February 10 Order, the Commission conditionally granted SPP’s application for recognition as a Regional Transmission Organization (RTO). Pursuant to Order Nos. 2000 and 2000-A,2 the Commission directed SPP to fulfill several requirements prior to being recognized as an RTO. As discussed below, we will accept in part, and reject in part, SPP’s compliance filing and direct a further compliance filing.

2. This order encourages RTO participation and ensures the establishment of efficient and reliable markets throughout the region, while preventing undue discrimination in the provision of electric transmission services.


3. We recognize that SPP has made significant progress in satisfying the prerequisites for RTO status, and other requirements, set forth in the February 10 Order. In particular, we recognize: (1) the timely, significant action of SPP members to seat a fully-independent Board of Directors and to modify its governance structure; (2) SPP’s actions in support of the organization and incorporation of the Regional State Committee (RSC); (3) SPP’s leadership in developing a regional transmission plan in an expedited manner; (4) the modifications to its tariff to ensure that SPP is the sole transmission provider; (5) SPP’s efforts to obtain clear authority to exercise day-to-day operational control over the appropriate transmission facilities in its footprint; (6) SPP’s selection of an independent market monitor; (7) SPP’s efforts to obtain clear, precise authority to independently and solely determine which projects to include in the regional transmission plan and the priority of those projects; and (8) its ongoing efforts to develop a seams agreement with the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). As discussed in this order, upon further action by SPP to satisfy the requirements of the February 10 Order, SPP will be recognized as an RTO.

Background

4. SPP is an Arkansas non-profit corporation, serving more than four million customers in a 250,000 square mile area, covering all or part of the States of Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. SPP’s membership includes 14 investor-owned utilities, six municipal systems, eight generation and transmission cooperatives, three state authorities, one federal power marketing agency, two independent power producers, and 16 power marketers.

3 Exhibit No. SPP-1 (Testimony of Nicholas A. Brown) and Attachment C (SPP Regional Map).

4 Id. SPP existing members are: American Electric Power Company-Public Service Company of Oklahoma and Southwestern Electric Power Company; Aquila, Inc. Missouri Public Service Company, St. Joseph Light & Power Company, and WestPlains Energy; Cleco Power LLC; Entergy Services, Inc.; Exelon Power Team; Kansas City Power & Light Company; Oklahoma Gas and Electric Services; Southwestern Public Service Company; The Empire District Electric Company; Westar Energy-Western Resources, Inc. and Kansas Gas & Electric Company; Arkansas Electric Cooperative Corporation; East Texas Electric Cooperative, Inc.; Kansas Electric Power Cooperative, Inc.; Midwest Energy, Inc.; Northeast Texas Electric Cooperative; Sunflower Electric Power Corporation; Tex-La Cooperative of Texas, Inc.; Western Farmers Electric Cooperative; City of Clarksdale, Mississippi; City of Lafayette, Louisiana; City Power & Light, Independence, Missouri; City Utilities, Springfield, Missouri; Public Service Commission of Yazoo City, Mississippi; The Board of Public Utilities, Kansas City, Kansas; Grand River Dam Authority; Louisiana Energy & Power (continued...)
Docket Nos. RT04-1-002 and ER04-48-002

5. SPP became a regional reliability council in 1968 and has administered a regional open-access transmission service tariff (OATT) for its member Transmission Owners (TOs) since 1998.

6. On October 15, 2003, SPP submitted the RTO application at issue in this proceeding. SPP’s filing included, among other things, proposed revisions to its Bylaws and Membership Agreement, as well as changes to its OATT.

**February 10 Order**

7. In the February 10 Order, we recognized that SPP had made significant steps toward satisfying all of the prerequisites for qualification as an RTO under Order Nos. 2000 and 2000-A. However, we found that SPP must make additional tariff, organizational and other changes prior to receiving final RTO authorization. As discussed more fully below, we directed SPP to: (1) implement its independent Board and modify its governance structure; (2) expand the coverage of its tariff to assure that SPP is the sole transmission provider; (3) obtain clear and sufficient authority to exercise day-to-day operational control over the appropriate transmission facilities within its footprint; (4) put in place an independent market monitor to monitor the competitiveness and efficiency of the market; (5) obtain clear and precise authority to independently and solely determine which projects to include in the regional transmission plan, and prioritize those projects; and (6) file with the Commission a seams agreement with the Midwest Independent Operator, Inc. (Midwest ISO). We also directed SPP to file, pursuant to section 205 of the Federal Power Act (FPA),\(^5\) its revised Bylaws and revised Membership Agreement, as modified in accordance with the February 10 Order. We further directed SPP to file its operating budget, for informational purposes, within 90 days of the date it obtains operational authority over transmission facilities within its footprint.

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Authority; Oklahoma Municipal Power Authority; Southwestern Power Administration; Calpine Energy Services, L.P.; InterGen Services, Inc.; Tenaska Power Services Company; Aquila Power - Aquila, Inc.; Cargill-Alliant, LLC; Cinergy Corporation; Constellation Power Source; Coral Power LLC; Duke Energy Trading & Marketing; Dynegy Marketing & Trade; Edison Mission Marketing & Trading, Inc.; El Paso Merchant Energy, L.P.; Mirant Americas Energy Marketing, L.P.; NRG Power Marketing, Inc.; TXU Energy Trading Company; and Williams Energy Marketing & Trading Company.

8. On March 19, 2004, the Commission held a technical conference with SPP and state and market participants (March 19 Outreach Meeting).\(^6\) The conference addressed issues relevant to SPP’s RTO formation, including conducting a cost-benefit analysis of the proposal, and coordinating state and federal efforts in order to expedite SPP’s application to become a fully-compliant RTO.\(^7\)

**SPP’s Compliance Filing**

9. On May 3, 2004, SPP submitted its compliance filing to the February 10 Order. SPP states that the filing reflects its commitment to move forward with becoming an RTO. SPP requests that the Commission declare SPP to be a fully-compliant RTO by July 2, 2004, within 60 days of the date it submitted the compliance filing.

10. SPP maintains that, pursuant to the February 10 Order, SPP’s Strategic Planning Committee (SPC) prepared and presented a series of recommendations to the SPP Board of Directors (or Board). SPP states that, on March 16, 2004, the Board approved SPC’s recommendations, subject to minor modifications, including the establishment of an independent Board on May 1, 2004.

11. In order to comply with the February 10 Order, SPP maintains that it further modified its Bylaws and OATT. These proposed modifications include: (1) installation of a totally independent SPP Board of Directors, effective May 1, 2004; (2) changes to the composition of SPP’s Members Committee and Corporate Governance Committee; (3) other Bylaw changes to better reflect SPP’s independence; (4) identification of transmission facilities under SPP’s operational authority; (5) clarifications to SPP’s planning process; and (6) tariff language providing for bundled load to be subject to the non-rate terms and conditions of SPP’s OATT.


\(^7\) Certain state commissions assert that facilities within their respective jurisdictions must obtain certain state approvals for RTO membership. At the March 19 Outreach Meeting, it was discussed that these state reviews, which might require a cost/benefit analysis, could proceed concurrently with Commission review of SPP’s RTO proposal. See Transcript of March 19 Outreach Meeting in Docket Nos. RT04-1-000, et al., at 140-155.
12. SPP further states that it has released funds to develop the balancing market, provided a report describing the respective responsibilities of SPP and the control areas within its footprint, explained the progress it has made to date with adjoining TOs on seams agreements, and provided a description and timetable for future filings directed in the February 10 Order.

13. SPP also states that it is committed to working with TOs that have been notified of the need for state approval prior to joining the RTO. SPP states that its filing attempts to address one of the states’ primary concerns, by directing that cost-benefit studies be conducted prior to the development of costly markets and congestion management systems.

**Notice of the Filing and Responsive Pleadings**

14. Notice of SPP’s compliance filing was published in the Federal Register, with comments, protests, and interventions due on or before May 24, 2004. The Council of the City of New Orleans, Louisiana (New Orleans Council) filed a notice of intervention, and Morgan Stanley Capital Group Inc., and the Louisiana Energy and Power Authority and the Municipal Energy Agency of Mississippi (collectively, LEPA) filed timely motions to intervene. The Southwest Industrial Customer Coalition (Southwest Industrial) filed a timely motion to intervene and protest. The following parties filed timely protests: The Louisiana Public Service Commission (Louisiana Commission); the Kansas Corporation Commission (Kansas Commission); East Texas Cooperatives, Electric Consumers Resource Council (ELCON); Southwestern Public Service Company (Southwestern Public Service); InterGen Services, Inc. and Redbud Energy LP (collectively, InterGen); TDU Intervenors, Lafayette Utilities System, Louisiana Energy and Power Authority, and Municipal Energy Agency of Mississippi (collectively, TDU Intervenors); Golden Spread Electric Cooperative (Golden Spread); and Sunflower Electric Power Corporation (Sunflower Electric). Kansas City Power & Light Company

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9 We note that, although characterized as untimely, LEPA’s motion for intervention was timely for purposes of the compliance filing.

10 The East Texas Cooperatives include: East Texas Electric Cooperative, Inc.; Northeast Texas Electric Cooperative, Inc.; and Tex-La Electric Cooperative of Texas, Inc.

11 TDU Intervenors include the Missouri Joint Municipal Electric Utility Commission, Oklahoma Municipal Power Authority, and the West Texas Municipal Power Agency.
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(KCPL) filed timely comments. American Electric Power Service Corporation (AEP) filed an untimely protest.

15. On June 1, 2004, SPP filed an answer to the protests.


Procedural Matters

17. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2003), the New Orleans Council’s notice of intervention and Southwest Industrial’s timely, unopposed motion to intervene serve to make those entities a party to this proceeding. In addition, we will accept AEP’s untimely comments, given its interest in this proceeding and the absence of any undue delay or prejudice to the parties.

18. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2003), prohibits an answer to a protest and response to an answer unless otherwise ordered by the decisional authority. We will accept SPP’s answer and Southwest Industrial’s response, because they have provided information that assisted us in our decision-making process.

Preliminary Issues

19. As an initial matter, we note that several parties filed comments in response to SPP’s compliance filing, which essentially reiterate their arguments on rehearing. These arguments call for transition to a postage-stamp rate design; consolidation of SPP’s multiple control areas; limitations upon the role of the RSC; participation of municipalities and cooperatives in the RSC; sanctions for TOs who are directed, but fail, to construct new or upgraded facilities; and resolution of jurisdictional conflicts concerning RTO membership. To the extent these arguments do not respond to the issue of whether SPP complied with the February 10 Order, we will not address these arguments here. We will address these rehearing arguments in a separate order.

20. In addition, Southwestern Public Service argues for the first time in this proceeding that SPP’s Bylaws should include limited liability provisions. This argument does not respond to the issue of whether SPP complied with the February 10 Order and

12 For example, the Louisiana Commission resubmitted its entire request for rehearing, in response to SPP’s compliance filing.
Docket Nos. RT04-1-002 and ER04-48-002

should have been raised in response to SPP’s initial filing in this case. Accordingly, we will not address that argument here.\footnote{In addition, Sunflower Electric expressed a general concern that SPP continue to address issues regarding administration of SPP’s transmission service request and generator interconnection queues. We will not address that concern here.}

21. The changes directed in the February 10 Order fall into the following general subject areas: (1) independence and governance; (2) scope and configuration; (3) operational authority; (4) tariff administration (including coverage of bundled and grandfathered load); (5) market monitoring; and (6) RSC role and responsibilities. In addition, we directed SPP to file its revised Membership Agreement and Bylaws pursuant to section 205 of the FPA. We address SPP’s compliance filing, relevant protests, and SPP’s answer below.

Filing Pursuant to Section 205

22. In its compliance filing, SPP does not indicate that it is submitting the revised Membership Agreement and Bylaws pursuant to section 205, as we directed in the February 10 Order. Nevertheless, we will treat those documents as if they have been submitted under section 205, since SPP’s compliance filing was properly noticed and interested parties have had an opportunity to comment. We find that the procedural requirements of section 205 have been satisfied.\footnote{In addition, parties have had an opportunity to address substantive issues pertaining to the revised Membership Agreement and Bylaws throughout this proceeding, and we addressed many of those issues in the February 10 Order. At this time, it is appropriate to assure the SPP has complied with the February 10 Order with respect to these documents and that they are on file pursuant to section 205.}

23. However, Order No. 614, FERC Stats. & Regs., Regulations Preambles ¶ 31,096 at 31,505 (2000), requires applicants to “unambiguously identify their proposed changes in a manner conforming to the Commission’s regulations, including properly formatting and designating their proposed tariff sheets.” Supplements are no longer recognized as a proper designation. Accordingly, we will conditionally accept for filing the revised Membership Agreement and Bylaws, provided SPP properly formats and designates those sheets in accordance with Order No. 614, and otherwise modifies those documents as provided for in this order, as a prerequisite to obtaining RTO status.
We now turn to the specific modifications regarding independence and governance, which we directed in the February 10 Order.

**Installation of Independent Board of Directors**

**February 10 Order**

In the February 10 Order, the Commission rejected SPP’s proposal to install a new, independent Board of Directors after it obtained RTO status. Instead, we directed SPP to install the independent Board of Directors as a prerequisite to RTO status.  

**Compliance Filing**

SPP states that its independent Board of Directors was established, effective May 1, 2004, and that the Board’s structure and authorities is set forth in section 4 of SPP’s Bylaws. Pursuant to section 8.0 of the Bylaws, changes regarding the structure and authorities of the Board of Directors must be approved by the Membership Committee.

**Discussion**

We commend SPP and its members for expeditiously installing its independent Board of Directors. We find that SPP has satisfied the February 10 Order, to the extent that SPP installed the Board on May 1, 2004, prior to receiving RTO authorization.

We note that the Kansas Commission has raised concerns regarding the Board’s independence from the SPP RSC. We will address its concerns below, in our discussion of the SPP RSC.

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15 February 10 Order at P 37.

16 SPP states that it held a Special Meeting of Members on April 27, 2004, where those changes to section 4 necessary to install the independent Board of Directors were unanimously approved, with an effective date of May 1, 2004.
Member Committee Representation

February 10 Order

29. Consistent with our determination in WestConnect,\textsuperscript{17} we directed SPP to amend the governance structure of the Members Committee, as a prerequisite to obtaining RTO status. We expressed our belief that expanding the stakeholder classes will provide a better representation of market participants that have not been adequately represented in the past and should prevent any one sector from having disproportionate control of the Members Committee.\textsuperscript{18}

Compliance Filing

30. SPP states that it revised the structure of its Members Committee by amending section 5.1.1 of the SPP Bylaws. As revised, according to SPP, two new committee members will be added, representing the retail/alternative power sector and the public interest sector. In addition, SPP maintains that the existing categories of representatives will be restructured into new categories that conform to the categories approved for other RTOs.\textsuperscript{19} The end result, states SPP, is that the Members Committee will consist of four representatives from investor-owned utilities; four representatives from electric cooperatives; two municipal representatives (including municipal joint action agencies); three representatives from the independent power producer/marketers sector; one representative from a state/federal power agency; and two representatives from the retail/alternative power/public interest sector.

Protests

31. Southwest Industrial and ELCON argue that balanced representation is still lacking on the Members Committee. ELCON contends that SPP’s stakeholder process bears no resemblance to the stakeholder participation model the Commission has approved for existing RTOs. ELCON argues that the number of representatives allotted to each stakeholder group is skewed in favor of supply-oriented members.

32. Southwest Industrial and ELCON argue that SPP’s Members Committee must explicitly provide for the inclusion of end-use customers (i.e., demand interests) and that

\textsuperscript{17} Arizona Public Service Company, et al., 101 FERC ¶ 61,033 (2002).
\textsuperscript{18} February 10 Order at P 42.
\textsuperscript{19} SPP cites WestConnect, supra, at n.14.
those customers must have a meaningful voting share and opportunity to participate.\textsuperscript{20} They argue that end-use customer participation is necessary to obtain a full and balanced perspective from entities that are financially-impacted by SPP Board of Director decisions. To ensure the proper balance between demand and supply interests, Southwest Industrial states that end-use customers’ voting percentage must equal 50 percent of the total Members Committee vote, with supply interests accounting for the other 50 percent. Alternatively, suggests Southwest Industrial, end-use customers should be allocated the same percentage of the Members Committee vote that is most common and most established among RTO stakeholder processes (which, according to Southwest Industrial is 20 percent of total stakeholder vote). Moreover, Southwest Industrial argues that the Membership Agreement and Bylaws present end-use customers with numerous hurdles to voting in an advisory capacity or participate in the stakeholder process,\textsuperscript{21} and that the Commission must direct that these hurdles be removed.\textsuperscript{22}

\textbf{SPP’s Answer}

33. SPP contends that the structure of its Member Committee accurately reflects the current composition of SPP. SPP states that, although presently there are no end-user members within SPP, the recently added slots allow for their representation if and when an end-user chooses to join. As far as participating in the stakeholder process, SPP contends that the process is open to members and non-members alike and that its stakeholder meetings are typically attended by non-member companies who are very much engaged in the deliberative process. With regard to arguments that SPP membership obligations (i.e., costs and fees) unfairly operate to deny end-users the ability to join, SPP contends that these arguments are outside of the scope of this


\textsuperscript{21} For example, Southwest Industrial states that, in order to qualify to participate and vote in the Members Committee in an advisory capacity, an end-use customer must become a Member, execute the Membership Agreement, agree to pick up a share of certain expenses, submit to the payment of an exit fee if it chooses to withdraw from the Members Committee, and enter into various financial commitments. In addition, Southwest Industrial states that the Membership Agreement and Bylaws restrict an end-use customer’s ability to use an agent to participate in the SPP stakeholder process.

\textsuperscript{22} Southwest Industrial suggests that New England Power Pool (NEPOOL) Agreement offers a “governance only” option to end-users, which exempts end-use customers from being allocated a share of NEPOOL expenses, any share of NEPOOL restructuring costs, and any share of NEPOOL participant defaults. Southwest Industrial argues that SPP should be required to adopt a similar mechanism.
proceeding. In any case, according to SPP, imposing such fees constitutes sound policy, as members should be financially invested in the membership as the quid pro quo for voting privileges and the right to participate in decisions affecting the direction and affairs of SPP. SPP adds that, to exempt one class from such fees would be unfair and discriminatory.

**Southwest Industrial’s Response**

34. Southwest Industrial argues that, although retail customers may vie for the two seats in the retail/alternative power/public interest sector, SPP does not guarantee that retail customers will obtain either of them. Southwest Industrial contends that SPP fails to define the eligibility criteria for this sector and the process for determining which entities occupy the seats if more than two entities compete for them. In addition, Southwest Industrial states that, even if the two seats are filled by end-use customers, representation of end-use customers would still be inadequate, compared to other independent system operators (ISOs) and RTOs. Southwest Industrial further contends that end-use customers’ interests are unique and cannot be adequately represented by any other industry sector (such as integrated public utilities, state commissions, cooperatives, or municipalities) in the stakeholder process. Southwest Industrial also disputes SPP’s argument that it would be unfair to exempt end-use customers from SPP’s financial membership obligations. Southwest Industrial contends that all end-use customers’ load is included in some load-service entity’s load for purposes of allocating SPP expense and therefore, full allocation of SPP expense to end-use customers would result in the potential for double-charging end-use customers.

**Discussion**

35. We recognize SPP’s efforts in amending its Members Committee structure. However, we find that SPP has not fully complied with our directive in the February 10 Order to amend its governance structure consistent with WestConnect. In WestConnect, two of the eight proposed sectors were earmarked for end-use customers (one for “large retail customers” and one for “small retail customers”). These seats were in addition to one of the two sectors that the Commission required to be added, i.e., public interest organizations, which included consumer advocates and other entities that are largely

23 According to Southwest Industrial, the New England Participants Committee, PJM Members Committee, New York Management Committee, and Midwest ISO Advisory Committee all include voting seats specifically earmarked for end-use customers.

24 101 FERC at P 44.
representative of end-use customer interests.\footnote{Id. at P 58.} Therefore, consistent with WestConnect, we will require that SPP revise its Members Committee by adding two additional stakeholder classes to ensure that all stakeholders are represented on the Members Committee. These two classes should include one seat for large retail customers and one seat for small retail customers.

36. We reject Southwest Industrial’s argument that end-users should be exempt from certain fees or requirements. We agree with SPP that exempting them from such fees or requirements would be unfair and discriminatory.\footnote{February 10 Order at P 43.}

**Corporate Governance and Board Nominee Selection Changes**

**February 10 Order**

37. The Commission noted that the Corporate Governance Committee is responsible for nominating persons for election to the board. Accordingly, we required, as with the Members Committee, that the Corporate Governance Committee structure be revised to include representation of all stakeholders and a more equitable allocation of slots to the various sectors. We also required SPP to codify and incorporate in its Bylaws the process that will be used for determining how potential Board nominees will be selected (e.g., acquiring the use of an independent search firm).\footnote{February 10 Order at P 43.}

**Compliance Filing**

38. SPP states that, under revised section 6.6 of the SPP Bylaws, the Corporate Governance Committee will now be populated with one representative from each of the member categories. In addition, according to SPP, new section 6.6b confirms that potential Board of Directors nominees will be selected using an independent search firm.


**Discussion**

39. We find that SPP has complied with the requirements of the February 10 Order with one exception. For the reasons stated above, we find that SPP has failed to comply with the February 10 Order with respect to representation of all membership categories. We will direct SPP to revise its Corporate Governance Committee to provide for an equitable allocation of slots to various sectors, in accordance with our determination regarding the Members Committee.

**Clarifying Advisory Role of Members Committee**

**February 10 Order**

40. The Commission found that sections 4.6.1 and 5.1.5 of SPP’s Bylaws create a perception of undue stakeholder influence over the Board of Directors, since it appears that the Board cannot hold a meeting or make a decision without the presence of stakeholders. We noted that such a requirement can be used, in practice, as a veto action. Accordingly, we directed that the restrictive language of those sections be removed.\(^{28}\)

**Compliance Filing**

41. SPP states that clarifying language has been added to section 4.6.1 of the Bylaws, which explicitly provides that the failure of the Members Committee (and/or the RSC) to attend shall not prevent the Board of Directors from convening and conducting business.\(^{29}\)

**Discussion**

42. We find that the added language in section 4.6.1 of the Bylaws fails to allay the Commission’s concerns set forth in the February 10 Order. While that language provides that the absence of a Members Committee or RSC representative shall not prevent the Board from “convening or conducting” business, we are specifically concerned that such absence might prevent the Board from voting and making binding decisions. Moreover,

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\(^{28}\) Id. at P 44.

\(^{29}\) More specifically, section 4.6.1 now provides that “the failure of representatives of the Members Committee and/or of the RSC to attend, in whole or in part, shall not prevent the Board of Directors from convening and conducting business.”
the language in sections 4.6.1 and 5.1.5 that provided the impetus for our concern in the February 10 Order remain.

43. Accordingly, we will direct SPP to remove the specified language and clarify the proposed language in section 4.6.1 to provide that the absence of Members Committee or RSC representatives shall not prevent the Board of Directors from convening and conducting business and taking binding votes.

Scope and Configuration

February 10 Order

44. The Commission determined that SPP conditionally satisfied Order No. 2000 requirements for scope. Nevertheless, in response to concerns regarding the adequacy of SPP’s scope (and more specifically, concerns regarding balkanized transmission control and interregional coordination), we directed SPP to file a seams agreement with the Midwest ISO and participate in the joint and common market with the Midwest ISO and PJM Interconnection, L.L.C. (PJM). We further required SPP to provide a timeline to develop and file seams agreements with the other utilities with which its members interconnect.30

45. Furthermore, in response to concerns regarding interregional coordination, we directed SPP to explain or include in its compliance filing: (1) the nature of its negotiations with nearby TOs, regarding seams issues; (2) the extent to which it has taken interested parties’ concerns into account in modifying the pro forma seams agreement; and (3) a timetable for filing these seams agreements.31

Compliance Filing

46. SPP asserts that it has conferred with representatives from the Midwest ISO and PJM concerning SPP participation in the joint and common market. Given the numerous seams issues facing those organizations, SPP maintains that the joint and common market initiative has been rolled into their Joint Operating Agreement (JOA).32 SPP states that it will participate in the joint and common market under its market to non-market protocols,

30 February 10 Order at P 63.
31 Id. at P 204.
32 SPP states that the Commission conditionally accepted for filing the Midwest ISO/PJM JOA in Docket No. ER04-375-000.
until it implements its imbalance market and determines that market-based congestion management is cost beneficial.

47. SPP further states that it recently executed a seams agreement with the Midwest ISO in the form of a Memorandum of Understanding (MOU). SPP asserts that it is also pursuing a broader joint operating agreement with the Midwest ISO, which is expected to be based upon the Midwest ISO/PJM JOA. SPP expects to present the framework for a joint operating agreement to SPP stakeholders, and finalize it with the Midwest ISO, within 60 days of the date of its compliance filing (i.e., by July 2, 2004). SPP contends that its progress on this issue to date is comparable to, or exceeds, the progress achieved by the Midwest ISO and PJM at the time they were formally recognized as RTOs.

48. SPP further contends that its timeline (attached as Appendix 5 to the compliance filing) provides the current status and target dates with regard to seams agreements and negotiations with neighboring entities.

**Protests**

49. Golden Spread disputes several aspects of the MOU. It argues that the primary weakness of the MOU is that either SPP or the Midwest ISO may unilaterally dissolve it upon 60 days’ notice. Golden Spread argues that any amendments to the MOU, including its termination, should be approved by the Commission. Moreover, Golden Spread argues that any amendments to a seams agreement between SPP and the Midwest ISO also should be approved by the Commission, and only upon a showing that SPP’s scope and configuration will still meet the requirements of Order No. 2000.

50. In addition, Golden Spread argues that SPP provided no empirical support that demonstrates the reasonableness of the target dates shown in SPP’s timeline for seams agreements with other neighboring utilities.

33 The MOU is Appendix 4 to SPP’s compliance filing.


35 It cites MOU section 6.1.
SPP’s Answer

51. SPP counters that its commitment to the joint and common market, and its timeline, represent a level of progress that satisfies the February 10 Order and exceeds the progress of other RTOs at the time of Commission approval. SPP states that concerns regarding the efficacy of the MOU, including its termination provisions, are unfounded, given that positive negotiations continue on the SPP/Midwest ISO JOA, with the parties anticipating a final agreement to be presented for stakeholder approval within the next month. SPP also contends that it developed the timetable based on the status of ongoing discussions and related input from SPP’s Strategic Planning Committee.

Discussion

52. We recognize SPP’s efforts in executing the MOU with Midwest ISO, included in Appendix 4 of its compliance filing, and its commitment to file a joint operating agreement with Midwest ISO within 60 days of its compliance filing. The MOU identifies the parameters of a seams agreement between SPP and Midwest ISO and follows the pro forma seams agreement included in SPP’s initial RTO application. However, we find that SPP has not fully complied with the February 10 Order’s requirement that SPP have on file a seams agreement with the Midwest ISO.

53. To satisfy the February 10 Order, the seams agreement must be filed pursuant to section 205 (and meet Order No. 614 requirements). In addition, the seams agreement must provide detail on how SPP and the Midwest ISO will coordinate RTO operations, including, but not limited to, the following:

- Procedures for ensuring Available Flowgate Capacity (AFC) and Available Transfer Capability (ATC) are calculated consistently, coordinated on a multi-system basis and published to all market participants;
- Procedures for developing consistent treatment of Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM);
- Type, and timing, of information exchange related to AFC, ATC, TRM and CBM;
- Procedures for coordinating emergency and restoration procedures, prevention of system collapse and instability;
- Procedures for coordinating operational model data updates and exchanging such data; and
Details on notification and coordination of maintenance outages of generation and transmission lines impacting inter-RTO transfer capability.

54. We recognize that the information described above may be reflected in the JOA that SPP plans to file. If so, we will review that filing and determine whether it satisfies the requirement of the February 10 Order for achieving RTO status. In addition, in response to Golden Spread’s concern about termination of the MOU, we will require that the agreements between SPP and the Midwest ISO reflect that any termination will not be effective except after Commission action on a filing of a notice of cancellation.

Operational Authority – Identification of Facilities Under SPP’s Control

February 10 Order

55. The Commission emphasized that, for RTO status, SPP must have clear and sufficient authority to exercise day-to-day operational control over the appropriate transmission facilities within its footprint. Accordingly, we directed SPP to submit a report clearly identifying the transmission facilities under its control. We required the report to include a detailed description of the then-current and proposed allocation of responsibilities between SPP and the control areas, and the capabilities of each entity to perform its proposed responsibilities. We directed SPP to adopt North American Electric Reliability Council (NERC) classifications of service functions, including: Reliability Authority, Balancing Authority, Interchange Authority, Transmission Service Provider, Transmission Owner, Transmission Operator, Market Operator, and Planning Authority. We required SPP to clearly state the responsibilities under each of these categories and any proposed changes in those responsibilities. We also directed SPP to study the feasibility of reducing its control areas and file, within one year of the February 10 Order, the outcome of its study.\(^{36}\)

Compliance Filing

56. Attached as Appendix 6 to SPP’s compliance filing is an “Operational Authority White Paper” (OA White Paper).\(^{37}\) SPP contends that the OA White Paper explains the

\(^{36}\) February 10 Order at P 79-80.

\(^{37}\) The OA White Paper at 8 provides that “SPP has the operational authority necessary to perform as an RTO under Order 2000. This authority is given to it principally by the SPP Membership Agreement (and associated Criteria), NERC Policies, and the Tariff. An analysis of authority in terms of the NERC functional model emphasizes that SPP performs much of its task using a hierarchal structure, and SPP has (continued…)}
procedures by which it will assume operational authority over member-owned transmission assets and how, within the NERC model, SPP will exercise this authority under normal operating conditions and during system emergencies to maintain system reliability. Appendix 6 also includes a map of the SPP footprint (SPP map), which depicts the transmission facilities over which SPP will hold day-to-day operational authority. SPP further states that it is examining the feasibility of reducing its control areas and expects to file a report with the Commission, as required by the February 10 Order.

Protests

57. East Texas Cooperatives and TDU Intervenors argue that SPP has failed to adequately identify the facilities over which it will have operational authority. They argue that the SPP map is unclear and inaccurate. They contend that other ISOs and RTOs have been required to provide a list of the lines, substations, and other transmission-related facilities being transferred to their functional control, and that SPP should be required to do the same.

58. TDU Intervenors further take issue with the OA White Paper. They contend that, rather than demonstrating that SPP will have hands-on involvement in day-to-day operations, in accordance with the February 10 Order, the paper confirms that SPP’s role will remain largely remote and supervisory. According to TDU Intervenors, the OA White Paper indicates that SPP will direct revisions to transmission maintenance plans only as permitted by agreements, without explaining any contractual limits on its authority to direct, or redirect, actions affecting the reliability of the system, as well as SPP’s ability to provide transmission service under the Tariff.” Appendix A to the OA White Paper includes a NERC Functional Responsibility Matrix, which indicates that, at Day 1, the SPP RTO will have sole responsibility for operating reliability; sole, ultimate or shared responsibility for certain planning responsibility functions; sole or shared responsibility for certain balancing functions; shared or no responsibility for certain market operations; no resource planning responsibility; ultimate, shared, or no responsibility for certain transmission operations functions; sole responsibility for interchange functions; sole or shared responsibility for certain transmission planning functions; sole responsibility for transmission service; and sole or no responsibility for certain transmission ownership functions.

38 East Texas Cooperatives contends that the map incorrectly indicates that some of its facilities are under SPP’s control.

39 They cite Westconnect, 101 FERC at P 100.

40 The cite OA White Paper at 8 (see fn.34, supra).
Moreover, TDU Intervenors contend that the OA White Paper is a non-binding document, and that any binding obligation for members to comply with SPP’s operational directives must be set forth in SPP’s Membership Agreement.

59. Golden Spread argues that the Commission should direct SPP to develop a bright-line functional test for determining the specific TO facilities that will be designated as tariff facilities and turned over to SPP’s operational authority. This test, according to Golden Spread, should be as specific as possible, setting forth detailed criteria that SPP will use to designate tariff facilities. In addition, Golden Spread argues that SPP TOs should be required to conform their own books and records regarding their transmission assets to the designation of tariff facilities.

**SPP’s Answer**

60. SPP maintains that its OA White Paper relies upon the NERC functional model to define the various functions necessary to ensure reliable operation of the transmission system and to explain the relationships between those entities that perform such functions. SPP states that its OA White Paper makes clear that SPP’s functional responsibilities, including its role as regional reliability coordinator, its authority and responsibilities as transmission provider under its OATT, and its coordination of interchange functions, meets the conditions of the February 10 Order with respect to control issues.

61. SPP adds that it expects to submit its study regarding the feasibility of reducing its control areas by February 10, 2005.

**Discussion**

62. We find that SPP has failed to satisfy the February 10 Order’s requirements regarding operational authority. In that order, we directed SPP to “clearly identify the transmission facilities under its control [and] obtain the necessary authority to exercise day-to-day control over those facilities under normal operating conditions and system emergencies to maintain system reliability” and provide a “report on such authority and

41. They cite SPP White Paper at 10, which provides that SPP will “direct revisions to transmission maintenance plans [and] request revisions to generation maintenance plans, as required and as permitted by agreements.”

42. To that end, East Texas Cooperatives further reiterates its rehearing argument that SPP should develop a single definition of “transmission” to determine which facilities will be designated as tariff facilities.
facilities that it will control.” This is a critical prerequisite to RTO status, in order to demonstrate that SPP is a public utility, with operational control over facilities subject to Commission jurisdiction. In addition, we note the recommendations of the U.S.-Canada Power System Outage Task Force Report, which stated, “FERC should not approve the operation of RTOs or ISOs, until they have met minimum functional requirements.”

Rather than submitting the directed report identifying the transmission facilities, SPP submitted a map, which lacks sufficient detail regarding the facilities that will be under its operational control. In accordance with the February 10 Order, as well as WestConnect, we will direct SPP to provide a list of all transmission facilities that will be transferred to its operational control. SPP must file this list as a prerequisite to obtaining RTO status.

Further, SPP has not demonstrated that it has acquired the authority to exercise day-to-day control over the transmission facilities. In the February 10 Order, we found that the Membership Agreement did not satisfy Order No. 2000 requirements in this regard, but we did not specifically direct changes to the agreement, and, in its compliance filing, SPP has made none. Neither the OA White Paper nor the Membership Agreement provides adequate specificity regarding SPP’s operational authority. Accordingly, we will direct SPP to revise the OA White Paper or the Membership Agreement, or provide some other binding document, in order to reflect SPP’s clear and sufficient authority to exercise day-to-day operational control over the appropriate transmission facilities within its footprint. As stated in the February 10 Order, in order to fulfill this requirement, SPP must include a detailed description of its proposed allocation of responsibilities between SPP and the control areas and the capabilities of each entity to perform its proposed

43 February 10 Order at P 79 (emphasis added).
45 101 FERC at P 88 (advising RTO applicants to provide a “complete listing of the transmission facilities that will be under the RTO’s operational control,” and a rationale for excluding any transmission assets that provide transmission service from the RTO’s operational control, and further encouraging applicants to continue working with all stakeholders in the region in order to determine the appropriate facilities to be placed under the RTO’s operational authority).
46 For example, we agree with protestors that the OA White Paper indicates, without sufficient explanation, that certain SPP functions as an RTO will be subject to “agreements,” which is inconsistent with Order No. 2000’s requirement that an RTO have clear and sufficient authority to exercise day-to-day operational control over the appropriate transmission facilities within its footprint.
responsibilities, and adopt the NERC classification of service functions.\footnote{See February 10 Order at P 80.} If SPP chooses to set forth its operational authority in the OA White Paper or some other document, it must incorporate those documents by reference in the Membership Agreement and file those documents under section 205 of the FPA.

65. With regard to Golden Spread’s argument that SPP must develop a bright line test for designating transmission facilities or a single definition of transmission facilities, we note that SPP and stakeholders are currently in the process of developing a single definition of transmission. As we noted in the February 10 Order, resolution of this issue will take time; we encourage the parties in this process. We require SPP to address this matter as part of its timetable to resolve issues regarding compensation for customer-owned transmission facilities.

**Grandfathered Agreements (GFAs) and Bundled Retail Load**

**February 10 Order**

66. In the February 10 Order, we recognized that treatment of grandfathered wholesale agreements (GFAs) and bundled retail load is a difficult issue with wide-ranging implications. We recognized that the issue impacts an RTO’s ability to effectively administer its tariff and operate markets. Accordingly, we encouraged transmission customers with GFAs to convert to direct service under the SPP OATT. However, we did not require such conversion or abrogate any contracts. Rather, consistent with Order No. 2000-A,\footnote{Order No. 2000-A at 31,375-75.} we required that TOs, on behalf of their entire load, including grandfathered wholesale and bundled retail loads, take service under the non-rate terms and conditions in the SPP OATT as a prerequisite to obtaining RTO status from the Commission.\footnote{February 10 Order at P 108.} We further required SPP to submit in its compliance filing: (1) disclosure of the magnitude of load that is proposed to be grandfathered wholesale, as well as bundled retail load, and to indicate what percentage of these loads will be to the total load served under SPP’s tariff; and (2) a schedule for converting its GFAs to the SPP OATT, consistent with the guidance provided to the Midwest ISO, to facilitate market operations.\footnote{Id. at P 110.}
Compliance Filing

67. SPP states that, under revised section 39 of its proposed OATT, each TO that is not otherwise taking network integration transmission service under SPP’s OATT is subject to the non-rate terms and conditions of the OATT for bundled retail load, including bundled load under GFAs. In addition, SPP contends that revised section 39 identifies the specific non-rate terms and conditions that would apply to bundled and grandfathered load. Accordingly, SPP states that transmission-owning members of SPP, on behalf of bundled and grandfathered load, will be required to designate resources and loads and will be subject to compliance with the ancillary service provisions for that load. In addition, SPP states that this load will be curtailed on a comparable basis with unbundled load and subject to comparable treatment with regard to new facilities.

68. Furthermore, SPP’s proposed Attachment W to its OATT is intended to identify all currently effective grandfathered agreements. SPP confirms that over 90 percent of SPP load is subject to at least the non-rate terms and conditions of SPP’s OATT, i.e., unbundled and/or non-grandfathered load is subject to all terms and conditions of SPP’s OATT, and bundled retail and grandfathered load is subject to the non-rate terms and conditions of SPP’s OATT. SPP expects that conversion of grandfathered load will occur in accordance with the terms of individual GFAs and the current (i.e., unrevised) SPP OATT, but SPP states that it will continue discussions with its members on this issue.

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51 See Appendix 9 to the compliance filing, SPP OATT, Fourth Revised Volume No. 1, Superseding Sheet No. 93, which provides: “[E]ach Transmission Owner (which is not otherwise taking Network Integration Transmission Service) is subject to the non-rate terms and conditions of this Tariff for: (1) its bundled retail load not having a choice of power suppliers; (2) its bundled retail load that had the right to choose a different power supplier under a state retail access program or legislation and that was retail load served by the Transmission Owner prior to the retail load receiving the right to choose a different supplier; and (3) its bundled load under Grandfathered Agreements. For purposes of this provision the non-rate terms and conditions are those that would apply to Network Customers except for (1) section 28 other than the provision in section 28.1 requiring Ancillary Services pursuant to section 3 and section 28.2; (2) section 29 other than section 29.3 and 29.4; and (3) section 34.1, 34.1 and 34.3. In addition, unless a [TO] executes a Service Agreement under this Part III, it will not be considered as taking Network Integration Transmission Service.”

52 See Appendix 10 to the compliance filing.
Protests

69. East Texas Cooperatives argue that several of their contracts should be included on the list of GFAs contained in proposed Attachment W. They contend that, under the SPP OATT, GFAs include transmission under bundled wholesale contracts, and that many of their contracts fall within that category.

70. InterGen argues that SPP has failed to satisfy the Commission’s requirement that all grandfathered and bundled retail load be subject to the non-rate terms and conditions of the SPP OATT. They argue that section 39.1 of the SPP OATT excludes from non-rate terms and conditions certain services, including the protocols for reservation of service, load forecasting and updates, and initiative service. In addition, InterGen argues that, without adequate explanation, SPP has exempted from non-rate terms and conditions unbundled transmission load under GFAs, as well as service provided under contracts with the Southwestern Power Administration.

71. InterGen and the Kansas Commission contend that SPP failed to provide a schedule for converting GFAs to the SPP OATT. The Kansas Commission further argues that SPP failed to adequately identify the magnitude of its grandfathered load. The Kansas Commission argues that the magnitude is extensive, and that, given the large number of GFAs in the SPP region, most of which contain evergreen provisions (according to the Kansas Commission), it is reasonable to assume that most of the GFA load may never be subject to certain energy market rules and procedures.

72. AEP argues that proposed section 39 would allow pancaked rates for certain intra-RTO transactions by TOs serving native load under the non-rate terms and conditions of the SPP OATT. AEP contends that these TOs, but not others, would pay rates for native

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53 They cite SPP OATT section 1.14a(2).

54 More specifically, they contend that the following group of wholesale power contracts with respective member cooperatives should be included in Attachment W: (1) contract with East Texas Electric Cooperative as selling party and East Texas Electric Cooperative and its member cooperatives as buying party; (2) contract with Northeast Texas Electric Cooperative as selling party and Northeast Texas Electric Cooperative and its member cooperatives as buying party; (3) contract with Tex-La Electric Cooperative of Texas as selling party and Tex-La Electric Cooperative of Texas and its member cooperatives as buying party.

55 Intergen cites SPP OATT, Volume No. 1, First Revised Sheet Nos. 92-93.

56 The Kansas Commission states that there are 417 GFAs at issue.
load service within their own rate zone, plus an additional fee for economy energy imports.\textsuperscript{57} This result, according to AEP, is unduly discriminatory and inconsistent with Commission regulations\textsuperscript{58} and the February 10 Order.

**SPP's Answer**

73. SPP contends that its compliance filing represents a good faith attempt to be responsive as possible to the February 10 Order. SPP states that, as a practical matter, precise quantification of the volume of load subject to GFAs is not possible, because, in many instances, there are multiple GFAs serving the same load. Consequently, SPP states that its compliance filing provides estimates of its current load profile and an updated list of GFAs. SPP maintains that its compliance filing addresses what it identifies as the Commission’s primary objective on this point, i.e., to place the vast majority of load within the SPP footprint under the SPP OATT.

74. With regard to the conversion issue, SPP states that the February 10 Order requires nothing more than SPP’s explanation that GFAs would terminate or convert in accordance with their contract terms.

**Discussion**

75. While we find that SPP has substantially complied with the February 10 Order’s requirement to put all load under its OATT, it is appropriate that all load be made subject to the non-rate terms and conditions of the OATT, in order to ensure that non-discriminatory service is provided thereunder. Therefore, SPP should remove any exceptions to such requirement from its OATT.\textsuperscript{59}

76. Regarding Intergen’s concern about the lack of a meaningful conversion plan, we did not require a specific plan to convert grandfathered agreements to SPP’s OATT in the February 10 Order. However, SPP has not fully complied with the requirement in the ________________

\textsuperscript{57} More specifically, AEP states that, under section 39, section 28.4 (allowing economy purchases to be imported by a network service customer to be imported at no charge) would not apply to TOs taking native load service under the non-rate terms and conditions of the SPP OATT, and transmission charges would apply to all economy imports. See AEP protest at 2-4.

\textsuperscript{58} AEP cites 18 C.F.R. § 35.34(k)(1)(ii) (2003), which provides that customers under an RTO’s OATT “must not be charged multiple access fees for the recovery of capital costs for the transmission service over facilities that the [RTO] controls.”

\textsuperscript{59} For example, certain exceptions included in proposed section 39 of SPP’s OATT should be removed.
February 10 Order that it disclose the magnitude of its grandfathered wholesale and bundled retail load, the percentage of loads that will be to the total load served under the SPP OATT, and a schedule for converting its GFAs to the SPP OATT, consistent with the guidance provided to the Midwest ISO.\textsuperscript{60} We will require SPP, as it commits to do, to follow our guidance in Midwest ISO orders to develop a mechanism to convert GFAs to the SPP OATT to ensure efficient, non-discriminatory market operations. We believe this commitment should address Kansas Commission’s concern about treatment of such loads in operating markets.

77. In response to AEP’s concerns, it is not clear that proposed section 39 will result in pancaked rates. Accordingly, we will not require any changes to section 39 on this point. However, we agree with AEP that, under the Commission’s regulations, customers should not be charged multiple access fees.\textsuperscript{61}

\textbf{Compensation for Customer-Owned Transmission Facilities}

\textbf{February 10 Order}

78. In the February 10 Order, the Commission addressed concerns regarding the inclusion of more than one TO’s facilities under SPP’s control within a single transmission-pricing zone, as well as distribution of revenues by SPP to such TOs. We recognized that SPP’s resolution of these issues will take time. We referred parties to relevant Commission precedent, including \underline{Wolverine}.\textsuperscript{62} We further directed SPP to include in its compliance filing a timetable for resolving such concerns.\textsuperscript{63}

\textbf{Protests}

79. East Texas Cooperatives and TDU Intervenors argue that SPP failed to submit a timetable for resolving concerns related to compensation for customer-owned transmission facilities, as directed in the February 10 Order. They recognize that SPP has


\textsuperscript{62} Midwest Independent Transmission System Operator, Inc., 101 FERC ¶ 61,004 at 61,010 (2002), reh’g pending. In that case, we stated that participation of new TOs in RTOs would be accommodated by providing appropriate compensation for their transmission facilities, whether by establishing such entities as separate pricing zones or incorporating such entities into existing pricing zones.

\textsuperscript{63} February 10 Order at P 115.
Docket Nos. RT04-1-002 and ER04-48-002

established a stakeholder task force to examine these issues, but state that SPP must submit a timetable to ensure concerns are resolved in an expeditious manner.  

Discussion

80. SPP provided no timetable pertaining to compensation for customer-owned transmission facilities. We will direct SPP to submit the timetable as prescribed in the February 10 Order.

Schedule 1 Scheduling Charges

February 10 Order

81. The Commission directed SPP to address issues concerning the purchase of reactive power and Schedule 1 rate pancaking with interested parties and file a report, within one year of the February 10 Order, regarding its progress on these and other ancillary service issues.

Compliance Filing

82. SPP asserts that, through its recently established VAR Compensation Task Force, discussions are underway to develop options for a single, consistent regional approach to the provision of reactive power service and related compensation for all generators within the SPP region. SPP expects to file the study on ancillary service issues within the directed time frame.

Discussion

83. We accept SPP’s commitment to file the report in a timely fashion. We note that SPP’s compliance filing is silent with respect to progress on Schedule 1 rate pancaking. Thus, we will require that SPP report within 60 days on its progress on addressing Schedule 1 rate pancaking issues raised by intervenors.

64 East Texas Cooperatives further reiterates its rehearing arguments that SPP must develop a single definition of “transmission,” as well as a mechanism for compensating TOs in multiple pricing zones.

65 February 10 Order at P 156.
Available Transmission Capability (ATC) Calculations

February 10 Order

84. The Commission required SPP to clearly explain its process for arriving at its ATC calculations within 60 days of the February 10 Order. We stated that the process must include SPP’s oversight of data collection and calculation for all set-asides by the TOs, including CBM and TRM. We indicated that such oversight could include, for example, SPP or its agent conducting audits of the TOs in this area.66

Compliance Filing

85. SPP asserts that Attachment C to the SPP OATT sets forth its methodology for determining short-term ATC. SPP states that its methodology is based on and consistent with the process outlined in the NERC report, “Available Transfer Capability Definitions and Determination.”

86. SPP contends that Attachment C allows for consideration of CBM and TRM in determining ATC. However, to date, SPP has chosen not to include a set-aside for CBM in its computation of ATC.

87. SPP further states that Attachment O to the SPP OATT sets forth its methodology for determining long-term ATC. SPP maintains that, to date, it has chosen not to set aside any transmission capacity for TRM or CBM.

Protests

88. TDU Intervenors argue that SPP’s response on the issue of ATC calculations is inadequate. TDU Intervenors assert that Attachments C and O of SPP’s OATT already had been included in SPP’s RTO proposal, on which the Commission ruled in the February 10 Order, and that those attachments remain unchanged in parts relevant to ATC calculations. They further argue that SPP has failed to explain the process for SPP’s oversight of data collection and calculation for all set-asides by the TOs.

SPP’s Answer

89. SPP states that the Commission’s purpose in the February 10 Order was to solicit data that would address concerns relating to CBM and TRM set-asides and their impact

66 Id. at P 162.
on SPP’s ATC calculations. SPP states that its compliance filing is fully responsive in that regard.

**Discussion**

90. We agree with TDU Intervenors that SPP’s response with regard to ATC calculations is unclear. However, the information required to answer our concern does not require an amendment to SPP’s Tariff.

91. The source of the data used in SPP’s process for deriving ATC is unclear. Therefore, we will require that SPP submit, for Commission review, examples detailing how ATC is derived under its Tariff with regards to Attachments C and O. More specifically, the example must provide how the data is collected (e.g., Level 2 or 3).  

**Market Monitoring**

**February 10 Order**

92. In the February 10 Order, we required SPP to have an independent market monitor (IMM) in place to oversee the reliable operation of the transmission system, as a prerequisite to obtaining RTO status from the Commission. We directed SPP to provide a market monitoring plan no later than 60 days prior to implementing Phase 3 of its energy imbalance market. We stated that this plan should include appropriate market power mitigation measures to address market power problems in the spot markets and a clear set of rules governing market participant conduct, with the consequences for violations clearly spelled out. We also stated that the plan should include the process that the IMM will use if the IMM finds that the markets are not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure. We also directed SPP’s market monitoring plan to include periodic reports

67 See Order No. 2000 at 31,143, where we state that at Level 2, the RTO would receive raw data from TOs and itself calculate ATC values. At Level 3, the RTO would itself calculate ATC values based on data developed partially or totally by the RTO.

68 As detailed in the February 10 Order, SPP’s proposed market development plan included three phases: (1) imbalance market and market monitoring (Phase 1), which, in turn, will be introduced in three increments, to be fully implemented in November 2004; (2) financial transmission rights for market-based congestion management, to be implemented in November 2005 (Phase 2); and (3) regional ancillary service mechanisms, to be implemented in Fall 2005 (Phase 2).
prepared by the IMM. We directed these reports to incorporate market metrics to provide a basis for measuring performance of these markets across RTOs and ISOs, and to compare the performance of the market in each RTO or ISO over time. We stated that metrics will also be developed to provide standard performance information on a monthly basis.\(^{69}\)

**Compliance Filing**

93. SPP states that, in order to comply with the February 10 Order, it formed the IMM Selection Task Force (Task Force) on February 25, 2004. In late April 2004, the Task Force presented its recommendation to the SPP Board of Directors, and, on April 27, 2004, the Board of Directors voted to contract with Boston Pacific as SPP’s IMM.

**Protests**

94. The Louisiana Commission expresses concerns regarding the independence of SPP’s chosen IMM. It states that Boston Pacific has and continues to represent market participants within the Southeast in regulatory proceedings before state regulators and before the Commission. The Louisiana Commission states that SPP’s compliance filing lacks details regarding its agreement with Boston Pacific.

95. To that end, TDU Intervenors argue that the Commission should require SPP to file its contract with the IMM, in order to allow adequate review by interested parties and ensure that the IMM has requisite authority and resources to oversee the safe and reliable operation of the transmission system, in accordance with the February 10 Order.

96. Similarly, InterGen argues that the role of the IMM, including its functions and power, must be more clearly defined. InterGen contends that the IMM must actively participate in regional planning and development of SPP’s RTO markets and must be authorized to oversee all aspects of the transmission system and non-discriminatory provision of service, including administration of the Open Access Same Time Information System (OASIS), and all system impact and facilities studies. InterGen further states that the Commission must ensure that the market monitor is provided the appropriate tools to accomplish its objectives, and more specifically, that the IMM should have explicit authority to review and challenge approval or disapprovals of specific transmission service requests and operational decisions, and the right to access all personnel, base case models, studies, data and assumptions.

\(^{69}\) February 10 Order at P 173.
SPP’s Answer

97. SPP contends that certain parties’ requests for more details regarding the market monitoring plan and the oversight roles and functions to be performed by the IMM are premature and represent a collateral attack on the February 10 Order. SPP contends that the February 10 Order did not require such details because SPP’s energy markets are still developing. In any case, SPP maintains that the IMM functions already established in section 3.17 of SPP’s Bylaws are consistent with the development of IMMs in other RTOs.70

Discussion

98. We share protestors’ concerns regarding the independence of SPP’s IMM, i.e., Boston Pacific. Accordingly, due to conflict-of-interest concerns, we find that a firm may not at once act as a market monitor for an RTO and have financial relationships with parties that have an interest in that RTO’s market or other markets that are connected to it. We further find that, in order to ensure that Boston Pacific, or any other chosen IMM, has sufficient independence as a market monitor, SPP must file its contract with its IMM. The contract should clearly reflect that the IMM may not: (1) directly represent market participants within SPP’s region in proceedings before state regulators or this Commission; (2) work for clients with SPP-related business interests; or (3) work for clients that have business interests in markets inextricably connected to SPP (such as the Midwest ISO). SPP must file its contract with its chosen IMM within 30 days of the date of this order.

99. However, we find to be premature concerns pertaining to the IMM’s responsibilities and authorities. In the February 10 Order, we directed SPP to provide its market monitoring plan, including its market power mitigation measures, no later than 60 days prior to implementing Phase 3 of its energy market. We clarify that SPP must file this plan no later than 60 days prior to implementing increment three of Phase 1. When SPP files its market monitoring plan, it will be noticed and interested parties will have an opportunity to comment.

Transmission Planning and Expansion

February 10 Order

100. In the February 10 Order, the Commission commended SPP for its efforts in updating its transmission planning and expansion process. We noted that SPP is currently reviewing this function, with an eye toward making the process more open and participatory, and is evaluating a two-year planning cycle, with the first year’s focus on reliability, and the second year’s focus on market needs.\(^71\) We also found promising SPP’s ongoing efforts to accommodate third-party investment and participation in transmission upgrade projects.\(^72\) To that end, we required SPP to file specified milestones to ensure that it meets its planning cycle.\(^73\)

101. Nevertheless, we found that Attachment O of SPP’s OATT\(^74\) failed to provide SPP with the authority to independently oversee the regional transmission plan and solely determine the priority of transmission planning projects that address reliability and economic needs.\(^75\) We stated that TOs may perform studies and evaluate changes to their transmission systems; however, SPP should provide independent oversight of these studies to ensure that any proposed changes will not impede SPP’s ability to provide efficient, reliable, and non-discriminatory transmission service. Accordingly, we directed SPP to file changes to Attachment O of its OATT to reflect SPP’s authority to plan transmission and to make it consistent with provisions of the revised Membership Agreement, which address SPP’s and the TOs’ role in the transmission planning process.\(^76\)

102. We further required SPP to develop and file a transmission cost allocation plan by the end of 2004, addressing pricing treatment for the projects identified in SPP’s transmission plan. Regarding generator interconnector proposals, we directed SPP to follow compliance procedures in Docket No. RM02-1-000, Standardization of Generator Interconnection Agreements and Procedures.\(^77\) We noted that compliance with those

\(^{71}\) February 10 Order at P 185.

\(^{72}\) Id, at P 186.

\(^{73}\) Id, at P 187.

\(^{74}\) Attachment O sets forth SPP’s transmission planning and expansion procedures.

\(^{75}\) February 10 Order at P 188.

\(^{76}\) Id.

procedures will be handled in that case, and our acceptance of SPP’s proposal here is subject to the outcome of that proceeding.\footnote{February 10 Order at P 189.}

**Compliance Filing**

103. SPP states that revised Attachment O specifically provides that SPP will independently perform regional transmission planning studies that will assess the reliability and economic operation of the SPP system.\footnote{See Appendix 7 to the compliance filing.} SPP contends that revised Attachment O also vests SPP with ultimate authority to determine and resolve planning violations, subject only to dispute resolution procedures and review by the Commission or state regulatory authorities, where appropriate.

104. SPP also attaches to its compliance filing a timeline depicting the specific milestones associated with its two-year expansion plan.\footnote{See Appendix 8 to the compliance filing.} SPP expects to submit its transmission cost allocation plan on or before December 31, 2004.

**Protests**

105. Golden Spread, Sunflower Electric, TDU Intervenors, and Southwest Industrial take issue with various aspects of Attachment O. They argue that SPP has made only minor modifications, and that the underlying procedures that gave rise to Commission concerns about the absence of SPP control remain. For example, TDU Intervenors and Southwest Industrial argue that, under section 1.0 of Attachment O, SPP TOs establish, and need only conform to, their own planning criteria. Southwest Industrial argues that SPP must independently review TOs’ transmission planning criteria to ensure that the criteria do not impede SPP’s ability to provide efficient and non-discriminatory transmission service.

106. These parties further argue that, while under section 2.0, SPP can independently perform regional transmission planning studies, SPP should be allowed, or required, to initiate such studies. Golden Spread states that, under section 3.0, which addresses the process for determining the need for new facilities,\footnote{That section provides that, when a need for new or upgraded facilities exists, the “situation shall require submittal of a transmission plan for review by the Transmission (continued…)} it appears that only SPP’s members

\footnote{(2003), order on reh’g, Order No. 2003-A, 106 FERC ¶ 61,220 (March 5, 2004), reh’g pending.}
may initiate an expansion plan. Moreover, Golden Spread argues that section 3.0 leaves unclear what options are available to a customer if no plan is submitted in the first place.  

107. TDU Intervenors further contend that section 2.0 should be revised to state that SPP must plan and construct its system to “reliably and economically serve the needs of all customers in the region, including historical and native load customers and their projected load growth.”

108. Golden Spread further contends that SPP must acquire from different control area operators additional information that would be useful to determining which long-term upgrades are necessary or desirable. This information should include data related to out-of-merit order dispatch of generation within the control area, which is necessitated by internal transmission constraints or other transmission-related reliability considerations.

109. TDU Intervenors further contend that SPP’s specified milestones for ensuring that it meets its planning cycle are inadequate and devoid of content.

**SPP’s Answer**

110. SPP contends that its specified milestones directly correspond to the February 10 Order’s requirement that SPP provide them. SPP further states that its proposed revisions to Attachment O satisfy the conditions in the February 10 Order, and that certain parties have urged wholesale changes to Attachment O, which do not comport with the deficiencies found in the February 10 Order.

111. SPP further maintains that the proposed revisions to section 2.0 of Attachment O vest SPP with independent, final authority to pass on any upgrade or expansion proposal, Provider . . . . This review can be initiated by any Member requesting firm transmission service under any applicable tariff.”

Golden Spread also reiterates its rehearing argument that SPP should be given authority to impose sanctions on TO that are directed to construct new facilities or upgrades but fail to do so.

TDU Intervenors at 5 (citing Wholesale Market Platform White Paper, Appendix A, Page 14 of PDF version of White Paper, and PJM interconnection, L.L.C., 96 FERC ¶ 61,061 at 61,240 (2001)). TDU Intervenors further reiterate their rehearing argument that TOs must have an enforceable obligation to build and that SPP must include provisions for third-party participation in construction and ownership of transmission.
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subject to dispute resolution procedures and review by this Commission or state commissions, where applicable. SPP argues that these changes confirm SPP’s authority to independently decide which projects will be included in the regional plan and how they will be prioritized. While it is true that the planning criteria used are provided by the individual TOs, SPP states that the criteria must meet or exceed SPP Criteria and the NERC Planning Standards.

112. In any case, SPP argues that nothing in the February 10 Order denies TOs the right to participate in the planning process. Indeed, SPP states that TOs are proper participants in transmission studies and deliberations concerning proposed changes to their transmission systems. To that end, SPP contends that the planning protocols in other RTOs provide for similar involvement of TOs in the planning process.\(^\text{84}\)

113. Finally on this issue, SPP adds that it has recently embarked on an initiative through its stakeholder process to develop policies addressing transmission cost allocation and participant funding issues, with a goal of completing the initiative by the end of 2004.

Discussion

114. Consistent with the requirements in the February 10 Order, we will accept for filing SPP’s revisions to Attachment O and its timeline depicting the specific milestones in the two-year expansion plan. SPP’s planning framework provides that SPP’s planning staff will develop the regional transmission expansion plan consistent with good utility practice.

115. We do not share concerns regarding SPP’s independence from TOs over planning criteria. We find that, through its independent Board, SPP will exercise sufficient oversight over transmission planning activities. While section 1.0 of Attachment O allows TOs to develop their own transmission planning criteria, their criteria must conform to SPP Criteria and NERC Planning Standards. SPP has made it evident that its staff is vested with planning responsibility, independent of the TOs. Attachment O provides that the input of TOs and other stakeholders will be considered in the planning process, but will not impede SPP’s ability to provide non-discriminatory transmission planning criteria.

116. In addition, we find that Attachment O addresses Golden Spread’s concerns about the initiation of an expansion plan under section 3.0. Attachment O sets forth the process

\(^\text{84}\) SPP cites Midwest ISO Operating Agreement, Appendix B, “Planning Framework,” as allowing a collaborative process for transmission planning.
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for determining the need for new facilities, while including customers, members, and other entities that may be impacted. Attachment O states that a review can be made by the Transmission Provider, any SPP Member, or can be initiated by any SPP organizational group. Furthermore, if the TO is unable to determine alternatives, then SPP can establish a task force that includes “facilities that might be affected by the limiting facility.” We note that SPP has initiated regional transmission planning meetings.

117. TDU Intervenors argue that section 2.0 should be revised to include historic and native load customers. Golden Spread comments that, to ensure the usefulness of projects, SPP should obtain information from other control areas. We expect that, as an RTO, SPP will solicit all resources, including historic and native load customers, in the region to ensure an effective transmission expansion plan that addresses the region’s reliability and economic transmission needs. SPP will perform regional transmission planning studies to assess reliability and economic operation of the SPP transmission system.

**Regional State Committees**

**February 10 Order**

118. In the February Order, the Commission stated that it fully supported the creation of a Regional State Committee (RSC) within the SPP footprint.\(^{85}\) We stated that a representative RSC will benefit SPP and market participants by instituting a partnership between this Commission and state commissions, through which regional issues can be addressed. However, we found that the SPP’s and Supporting Commission’s\(^{86}\) proposal concerning RSCs did not adequately address several important issues.

119. We directed SPP to modify its Bylaws to incorporate only the following functions.\(^{87}\) More specifically, we stated that the RSC should have primary responsibility for determining regional proposals and the transition process in the following areas: (1) whether and to what extent participant funding would be used for transmission enhancements; (2) whether license plate or postage stamp rates will be used for the regional access charge; (3) financial transmission right (FTR) allocation where a locational price methodology is used; and (4) the transition mechanism to be used to

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\(^{85}\) February 10 Order at P 218.

\(^{86}\) The Supporting Commissions included the Arkansas, Missouri and Oklahoma Commissions.

\(^{87}\) February 10 Order at P 218.
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.. assure that existing firm customers receive FTRs equivalent to the customers’ existing firm rights. We stated that, if the RSC reaches a decision on the methodology that should be used, SPP would file this methodology pursuant to section 205 of the FPA, and that SPP can also file its own proposal under section 205.\(^{88}\)

120. The Commission further stated that the RSC should determine the approach for resource adequacy across the entire region, and that, with respect to transmission planning, the RSC should determine whether transmission upgrades for remote resources will be included in the regional transmission planning process, as well as the role of TOs in proposing transmission upgrades in the regional planning process.\(^{89}\)

**Compliance Filing**

121. SPP states that revised section 7.2 of its Bylaws essentially adopts, verbatim, the modifications indicated in the February 10 Order. In addition, SPP contends that the Bylaws contain no provisions regarding the RSC voting procedures as they relate to section 205 filings.

122. SPP notes that, on April 23, 2004, SPP announced the incorporation of the SPP RSC. The initial meeting of the SPP RSC occurred on April 26, 2004, during which state representatives were named, the board of officers was elected, bylaws were approved, and policy statements were approved on a joint cost/benefit study and transmission expansion funding principles. SPP contends that the SPP RSC consists of retail regulatory commissioners from agencies in Arkansas, Kansas, Louisiana, Missouri, New Mexico, Oklahoma, and Texas. SPP states that the incorporation of the SPP RSC reflects the cooperative efforts of the state commissions and represents an important milestone toward formal recognition of the SPP RTO.

**Protests**

123. The Louisiana Commission disputes SPP’s representation that the Louisiana Commission has a representative on the SPP RSC. The Louisiana Commission states that it has not agreed to join the RSC, because it does not regulate a utility that has applied to join the SPP RTO.

124. The Kansas Commission argues that, in contravention of the February 10 Order, SPP retained language in section 7.2 of its Bylaws, which gives the RSC the authority “to

\(^{88}\) Id. at P 219.

\(^{89}\) Id. at P 220.
provide both direction and input on all matters pertinent to the participation of Members of the SPP.” The Kansas Commission argues that SPP’s Bylaws now provide the RSC with both general and specific decision-making authority, rather than the specific decision-making authority required by the February 10 Order. The Kansas Commission argues that, unless the Commission rejects SPP’s compliance filing, the RSC will have specific decision-making authority in areas directed by the Commission and will potentially also have expansive decision-making authority in virtually all other areas.

125. In addition, the Kansas Commission expresses continued concern regarding the SPP Board of Directors’ independence from the RSC. The Kansas Commission argues that SPP must clarify that the RSC will have the authority to make recommendations, but will not have decisional authority over the SPP Board of Directors.

SPP’s Answer

126. SPP states that its compliance reflects the RSC’s ability to require SPP to make filings on its behalf, without impinging upon SPP’s ability to submit an alternative or opposing filing. SPP further states that, along with the stakeholders, the RSC will provide input for the independent consideration of the Board of Directors; SPP confirms that its Board will make independent decisions.

Discussion

127. We find that SPP has complied with February 10 Order requirements on this issue. SPP’s proposed revisions to section 7.2 of its Bylaws incorporate almost verbatim the “primary responsibilities” we set out in the February 10 Order.90

128. Section 7.2 does retain the language that the RSC “shall be established to provide both direction and input on all matters pertinent to the participation of Members in SPP.” However, contrary to the Kansas Commission’s argument, that language is not inconsistent with our directive that SPP modify its Bylaws to “incorporate” only the primary responsibilities we delineated. Like any other market participant, the RSC should provide “direction and input” into the SPP process. However, it is only with regard to the areas where the Commission has accorded the RSC “primary responsibility” where the RSC can direct an action of SPP.

90 The only difference is that proposed section 7.2 provides that “nothing in this section prohibits SPP from filing its own related proposal(s) pursuant to section 205.” The February 10 Order simply stated that SPP can file its own proposal under section 205. We find the difference irrelevant for purposes of this order.
Budget Review

February 10 Order

129. In order to allow the Commission to monitor costs expected to be incurred by SPP, we directed SPP to file its operating budget, within 90 days of the date it obtains operational authority over transmission facilities within its footprint.  

Protests

130. Southwestern Public Service argues that SPP’s Bylaws allow SPP to assess monthly costs to certain members, and, therefore, the Bylaws also should allow members to review those costs in order to determine if they are reasonable. It argues that such review is important, because TOs will be required to demonstrate to their state commissions that SPP costs were prudently incurred, before the states will allow the TOs to pass through such costs to their retail ratepayers.

Discussion

131. We will not require SPP to amend its Bylaws in the manner suggested by Southwestern Public Service. As indicated above, we have already required SPP to file its budget, and we will allow stakeholder comment on new budget items prior to approval. In addition, we will be auditing and reviewing SPP’s cost management, as SPP implements the phases of its market plan. Accordingly, at this time, we are not persuaded that SPP must amend its Bylaws to expressly allow members to review its costs.

The Commission orders:

(A) SPP’s compliance filing is hereby accepted in part, and rejected in part, as discussed in the body of this order.

91 February 10 Order at P 46.

92 Southwestern Public Service cites section 8.4, which provides that the costs recovered under the assessment will include but are not limited to all operating costs, financing costs, debt repayment, and capital expenditures associated with the performance of SPP’s functions as assigned by the Board of Directors.
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(B) SPP is hereby directed to submit a compliance filing, within 30 days of the date of this order, as discussed in the body of this order.

By the Commission. Commissioners Kelliher and Kelly concurring with a joint statement attached.

(SEAL)

Magalie R. Salas,
Secretary.
KELLIHER, Commissioner, *concurring*:

KELLY, Commissioner, *concurring*:

This order finds that SPP has complied with the requirements set forth in the February 10 Order with respect to the role of the Regional State Committee (RSC) in the SPP RTO. However, since the issuance of the February 10 Order, the U.S. Court of Appeals for the District of Columbia has issued two decisions, one providing guidance on the lawfulness of delegations of Federal authority to non-Federal bodies 93 and another regarding the Commission’s ability to affect the governance of a public utility, which includes an RTO.94

The Commission will take these court decisions into account in determining the role of the RSC in the order on rehearing of the February 10 Order.

___________________________
Joseph T. Kelliher

___________________________
Suedeen G. Kelly


Southwest Power Pool
REGIONAL STATE COMMITTEE
BYLAWS

Adopted: October 24, 2005
ARTICLE I

1. NAME. The organization shall be known as the Southwest Power Pool Regional State Committee (“SPP RSC”). The principal office of the SPP RSC shall be at such location, within the United States, as the SPP RSC Board of Directors shall from time to time establish. The SPP RSC may also maintain such branch offices and places of business as the SPP RSC Board of Directors may deem necessary or appropriate in the conduct of its business.

2. PURPOSE. The SPP RSC shall provide collective state regulatory agency input and participation in the Southwest Power Pool, Inc. (“SPP”) and SPP’s Board of Directors, committees, working groups and task forces, including any independent transmission system operator (“ISO”) or regional transmission organization (“RTO”) formed by the SPP. Such input and participation shall include but not be limited to: whether and to what extent participant funding will be used for transmission enhancements; whether license plate or postage stamp rates will be used for the regional access charge; determination of Financial Transmission Rights (“FTR”) allocations where a locational price methodology is used; determination of the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers’ existing firm rights; determination of the approach for resource adequacy across the entire region; determination of whether transmission upgrades for remote resources will be included in the regional transmission planning process; and determination of the role of transmission owners in proposing transmission upgrades in the regional planning process.

3. Nothing in the formation or operation of the SPP RSC as a FERC recognized regional state committee is in any way intended to diminish existing state regulatory jurisdiction and authority. Each state regulatory agency expressly reserves the right to exercise all lawful means available to protect its existing jurisdiction and authority.

ARTICLE II – MEMBERSHIP

1. MEMBERSHIP. Membership shall be open to all official governmental entities that:

(a) Regulate the retail electricity or distribution rates of transmission-owning members or transmission-dependent utility members of the SPP; or

(b) Are the primary regulatory agency responsible for siting electric transmission facilities in states where there are transmission-owning members of the SPP or independent transmission companies that own or operate transmission facilities associated with the SPP.

2. ASSOCIATE MEMBERSHIP. Associate membership shall be open to all official governmental agencies that:

(a) Are involved with energy planning, and or environmental issues that relate to electric transmission; or
(b) Are involved with consumer advocacy issues that relate to electric transmission; or

c) To all other entities that are approved by the SPP RSC Board of Directors for associate member status.

ARTICLE III – ANNUAL MEETING

The Annual Meeting of the SPP RSC (Annual Meeting) shall be held each year in conjunction with the fall meeting of the SPP Board of Directors, and/or at such time and place as may be determined by the SPP RSC Board of Directors. Notice of the time, place, and purpose of the meeting, shall be provided by mail or electronic means to each Member and Associate Member of the SPP RSC not less than fifteen (15) calendar days prior to the meeting, except that the agenda may be amended up to three (3) calendar days prior to the meeting in accordance with Article XI. At the Annual Meeting, all member regulatory agencies may have a seat and voice. The business of the Annual Meeting will be conducted by vote of the SPP RSC Board of Directors as provided for in these Bylaws.

ARTICLE IV – BOARD OF DIRECTORS

1. POWERS, RESPONSIBILITIES AND ACCOUNTABILITIES. The corporate business and affairs of the SPP RSC shall be managed by the SPP RSC Board of Directors, except as may be otherwise provided for in these Bylaws and/or the articles of incorporation (Articles of Incorporation) adopted by the SPP RSC Board of Directors.

2. COMPOSITION. Each member regulatory agency, as defined in Article II.1 of these Bylaws, may designate one Commissioner to serve on the SPP RSC Board of Directors. In the case of member state regulatory agencies organized without commissioners, an official of similar level may be designated. When any such person ceases to be the duly authorized representative of that Member, he or she shall be replaced on the SPP RSC Board of Directors by another representative from his or her state regulatory agency. A member state regulatory agency may replace its Director by notifying the Secretary of the SPP RSC by mail, facsimile transmission and/or electronic mail at least one business day in advance of any meeting of the SPP RSC Board of Directors.

3. RESPONSIBILITIES. The SPP RSC Board of Directors shall elect the officers of the SPP RSC and determine the general policies and direction of the SPP RSC. The SPP RSC Board of Directors may amend the Articles of Incorporation and Bylaws, take all other action requiring membership vote, and conduct other business as delineated in Article IX.

4. REGULAR MEETINGS. Regular meetings of the SPP RSC Board of Directors shall be held at such time and place as may be determined by the SPP RSC Board of Directors, except that the SPP RSC Board of Directors shall meet no less than one time each calendar year, in addition to the Annual Meeting. Notice of the time, place and purpose of the meeting(s) shall be provided by mail, facsimile transmission and/or electronic means to each Member and Associate Member of the SPP RSC not less than
seven (7) calendar days prior to the meeting, except that the agenda may be amended up to three (3) calendar days prior to the meeting in accordance with Article XI. Public notice shall also be given at the same time that it is given to each Member and Associate Member of the SPP RSC in accordance with Article XI.

5. SPECIAL MEETINGS. The President may call a special meeting(s) of the SPP RSC Board of Directors. Notice of the time, place and purpose of the meeting(s) shall be provided by mail, facsimile transmission and/or electronic means to each Member and Associate Member of the SPP RSC not less than three (3) calendar days prior to the meeting(s).

6. QUORUM If a Director from each of a majority of the member state regulatory authorities is present (either in person, by authorized telephonic or electronic means, or by designated proxy), a quorum exists for the transaction of business at any meeting of the SPP RSC Board of Directors, but if less than such majority is present at a meeting, a majority of the members that are present may adjourn the meeting without further notice. The SPP RSC Directors present at a properly noticed meeting may continue to transact business until adjournment, notwithstanding the withdrawal of enough members to leave less than a quorum. A member state regulatory agency may allow a proxy from the same agency to participate as a substitute for its designated SPP RSC Director at a meeting(s) of the SPP RSC Board of Directors by notifying the Secretary of the SPP RSC as provided for in these Bylaws.

7. PROXY – A request of a member state regulatory agency for recognition by the SPP RSC Board of Directors of a proxy to participate in a meeting of the SPP RSC Board of Directors must be received by the Secretary of the SPP RSC at least one business day in advance of the meeting at which the proxy is to be exercised. Where prior written notice is not possible, the designating Director shall submit written confirmation of this proxy no later than ten (10) calendar days after the applicable Board meeting takes place. The person who is identified as exercising the proxy cannot be the person submitting the request for recognition of the proxy. Notices of proxies must be sent by mail, facsimile transmission and/or electronic mail to the Secretary of the SPP RSC and identify the date of the meeting of the SPP RSC Board of Directors for which the proxy is authorized and identify by name, and position at the member state regulatory agency, the person who is authorized to exercise the proxy. The Secretary of the SPP RSC must receive a new request for recognition of a proxy for each meeting of the SPP RSC Board of Directors at which the proxy will be sought to be recognized. The SPP RSC Board of Directors will not recognize, for more than one meeting at a time, a proxy request by a member state regulatory agency. The request for recognition of a proxy must not identify more than one person as being authorized to exercise the proxy.

8. VOTING PROCEDURES. Each SPP RSC Director present (either in person, by authorized telephonic or electronic means, or by representation of the member state regulatory agency by a properly designated proxy) shall be entitled to one equally weighted vote. However, if a state has more than one state regulatory agency that is a Member of the SPP RSC, voting rights shall be divided equally among the SPP RSC Directors from that state present and voting (equating to one total vote per state). Elections shall be by ballot in contested elections and may be by voice or other means in uncontested elections. A plurality of votes cast shall elect. Changes in the Bylaws
shall require a vote consistent with Article XII of this document. All other matters shall be determined by a majority of the SPP RSC Directors present and voting, unless otherwise provided by the laws of the state where the SPP RSC is incorporated or these Bylaws.

9. ELECTRONIC VOTING. The President has the option and authority to conduct an electronic vote on non-policy, administrative matters, such as approval of minutes or appointment of the annual SPP RSC auditor, or on policy matters that have been discussed during a prior RSC meeting.

10. POSITIONS ON POLICY ISSUES. The SPP RSC Board of Directors will give direction to formation of issue statements, which will then be referred to member state regulatory agencies. A position approved by a majority of the SPP RSC Board of Directors may be issued as the SPP RSC’s position with identification of the participating and non-participating member state regulatory agencies. Individual member state regulatory agencies retain all rights to object to, support, or otherwise comment on, issue statements of the SPP RSC, including the attachment of a minority report or dissenting opinion, provided it is submitted in a timely manner. The SPP RSC Board of Directors may authorize intervention in proceedings before federal regulatory agencies and in related judicial proceedings to express the SPP RSC’s positions, and may retain legal counsel to represent the SPP RSC in such proceedings. Consistent with Article I, § 3 above, each individual state regulatory agency shall also retain all rights to intervene in and/or comment on such federal regulatory agency proceedings and/or related judicial proceedings.

ARTICLE V - OFFICERS

1. NUMBER AND TITLE. The officers of the SPP RSC shall be the President, Vice-President, Secretary, and Treasurer.

2. ELECTION, TERM, VACANCIES. The President, Vice-president, Secretary, and Treasurer shall be elected by the SPP RSC Board of Directors for a term of one year, or until their successors are elected. Officers shall be elected at the Annual Meeting to take office on the first day of January following the Annual Meeting at which elections are held. The SPP RSC Board of Directors may fill a vacancy among the officers other than the President to serve until the next scheduled election. In the case of a permanent vacancy in the office of the President, the Vice-President will succeed until the next scheduled election. The terms of the officers elected in 2004 shall be deemed partial terms. In the event of a vacancy or temporary inability to serve, the duties of the Secretary or Treasurer may be fulfilled by a designee of the SPP RSC Board of Directors.

3. GEOGRAPHIC BALANCE. The officers elected shall be SPP RSC Directors from different states.

4. DUTIES. The duties of the officers shall be as follows:

   (a) The PRESIDENT shall be the principal officer of the SPP RSC and shall preside at the Annual Meeting and all meetings of the SPP RSC Board of Directors, shall be
responsible for seeing that the lines of direction given by the SPP RSC Board of Directors are carried into effect – including the representation and presentation of all SPP RSC majority positions and minority reports and dissenting opinions of the member state regulatory authorities, and shall have such other powers and perform such other duties as may be assigned by the SPP RSC Board of Directors; including but not limited to: serving as the SPP RSC’s non-voting representative at the meetings of the SPP’s Board of Directors, performing or delegating presentations/speeches on behalf of the SPP RSC, designating member state regulatory agency staff members proposed by the state regulatory agency to carry out daily functions and operations of the SPP RSC, assigning member state regulatory agency staff members proposed by the state regulatory agency to committees and work-groups created by the SPP RSC and requesting technical support from SPP as necessary. The President (or other officer serving as the RSC representative at meetings of the SPP Board of Directors) shall also be responsible for requesting recusal of a Director where a conflict of interest may arise and for clearly stating on all matters whether he/she is representing the position of the SPP RSC or solely his/her member state regulatory agency.

(b) In the temporary absence or disability of the President, the VICE-PRESIDENT shall preside at meetings of the SPP RSC Board of Directors and have such other powers and perform such other duties as performed by the President. The Vice-President shall also serve as the SPP RSC’s non-voting representative at the meetings of the SPP’s Board of Directors. He or she shall have such other powers and perform such other duties as performed by the President or as may be assigned by the SPP RSC Board of Directors.

(c) The SECRETARY shall be responsible for keeping a roll of the Members and seeing that notices of all meetings of the SPP RSC Board of Directors are issued and shall see that minutes of such meetings are kept. The Secretary shall be responsible for the custody of corporate books, records and files, shall exercise the powers and perform such other duties usually incident to the office of Secretary, and shall exercise such other powers and perform such other duties as may be assigned by the President or the SPP RSC Board of Directors.

(d) The TREASURER shall be responsible for monitoring the receipt and custody of all monies of the SPP RSC and for monitoring the disbursement thereof as authorized, for assuring that accurate accounts of monies received and disbursed are kept, for execution of contracts or other instruments authorized by the SPP RSC Board of Directors, and for overseeing the preparation and issuance of financial statements and reports. The Treasurer shall give a report of the SPP RSC’s finances at the Annual Meeting. The Treasurer shall be an ex officio member of the finance committee, if such a committee shall be established by the SPP RSC Board of Directors, shall exercise the powers and perform such other duties usually incident to the office of Treasurer, and shall perform such other duties as may be assigned by the President or SPP RSC Board of Directors.

5. REMOVAL. An officer of the SPP RSC may be removed with or without cause by written vote of two-thirds of the total membership of the SPP RSC Board of Directors.
ARTICLE VI – MEMBER STATE REGULATORY AGENCY STAFF MEMBER PARTICIPATION

Member state regulatory agency staff members shall participate at the discretion of their respective member state regulatory agency, including but not limited to: attendance at SPP RSC and SPP Board of Directors meetings in support of or in lieu of member state regulatory agency commissioners, attendance and active participation in assigned SPP committees, working groups and task forces (including providing summaries of meetings and reporting to the SPP RSC members and associate members), active representation of the majority positions and minority reports or dissenting opinions of the SPP RSC member state regulatory authorities, and attending and actively participating in assigned SPP RSC committees and work-groups created by the SPP RSC Board of Directors (including providing summaries of meetings and reporting to the SPP RSC members and associate members). Member state regulatory agency staff members must clearly indicate whether they are representing the SPP RSC or solely their member state regulatory agency.

ARTICLE VII - COMMITTEES

1. ESTABLISHED. The SPP RSC Board of Directors may establish SPP RSC committees and work-groups as it deems necessary and provide for their governance.

2. COMPOSITION AND APPOINTMENT. The President shall appoint members of the SPP RSC committees. Unless otherwise provided by the SPP RSC Board of Directors, a committee may elect its chair. Members and Associate Members may participate in the work of committees and work-groups that relate to matters within their jurisdiction.

ARTICLE VIII – MEMBERS AND ASSOCIATE MEMBERS NOT BOUND

No vote of, or resolution passed by, the SPP RSC Board of Directors has any binding effect upon any member state regulatory agency, or any associate member, in the exercise of that entity’s powers.

ARTICLE IX - FISCAL RESPONSIBILITIES OF THE SPP RSC BOARD OF DIRECTORS

1. FISCAL YEAR. The SPP RSC Board of Directors shall establish the fiscal year of the SPP RSC.

2. FUNDING. Any funds shall be accepted or collected only as authorized by the SPP RSC Board of Directors.

3. DEPOSITORIES. All funds of the SPP RSC shall be deposited to the credit of the SPP RSC in fully insured accounts.

4. APPROVED SIGNATURES. Approvals for signatures necessary on contracts, checks, and orders for the payment, receipt, or deposit of money, and access to securities of the SPP RSC shall be provided by resolution of the SPP RSC Board of Directors. In all cases, two signatures shall be required and shall consist of either the
SPP RSC President or Vice-President and one other officer and/or the Executive Director.

5. **DELEGATED AUTHORITY.** For routine payment of meeting and travel expenses incurred by SPP RSC Members and their designees, including designated State Commission Staff members, the SPP RTO may act as agent for the RSC and make payment of such expenses in accordance with the RSC’s then-current Expense Reimbursement Policy. Such expenses shall be paid from the RSC’s approved budget. For items of non-routine and more financially significant nature, such as an RSC-commissioned cost-benefit study or a large conference or event, the RSC Board of Directors may provide approval to the appropriate person within the SPP RTO to pay for such expenses, acting as agent for the RSC.

6. **BONDING.** All persons having access to or major responsibility for the handling of monies and securities of the SPP RSC shall be bonded as provided by resolution of the SPP RSC Board of Directors.

67. **INDEMNIFICATION AND INSURANCE.** Indemnification and Directors and Officers insurance shall be provided by resolution of the SPP RSC Board of Directors in accordance with the Articles of Incorporation and the laws of the state where the SPP RSC is incorporated.

78. **BUDGET.** The annual budget of estimated income and expenditures shall be prepared for the fiscal year and approved by the SPP RSC Board of Directors in conjunction with the Annual Meeting. No expenses shall be incurred in excess of approved budget levels without prior approval of the SPP RSC Board of Directors.

89. **CONTRACTS AND DEBTS.** Contracts may be entered into or debts incurred only as directed by resolution of the SPP RSC Board of Directors.

910. **AUDITS.** A certified public accountant or other independent public accountant shall be retained by the SPP RSC Board of Directors to make an annual examination of the financial accounts of the SPP RSC. A report of this examination shall be submitted to the SPP RSC Board of Directors and made available to the general membership of the SPP RSC and the public.

119. **LEGAL COUNSEL.** Independent legal counsel may, if deemed necessary and appropriate, be retained by the SPP RSC Board of Directors to: (a) insure compliance with federal and state requirements; (b) review and advise on any and all legal instruments the SPP RSC Board of Directors executes, such as leases, contracts, property purchases, or sales; (c) for interventions before federal regulatory agencies and related judicial proceedings; or (d) for any other matters as determined necessary by the SPP RSC Board of Directors – including those matters that are deemed to be administrative in nature.

142. **PROPERTY.** Title to all property shall be held in the name of the SPP RSC, unless otherwise approved by the SPP RSC Board of Directors; or otherwise required by law.
123. INVESTMENT. The Treasurer shall invest the funds of the SPP RSC in accordance with the direction of the SPP RSC Board of Directors or any committee of the SPP RSC Board of Directors appointed for such purpose.

ARTICLE X - PARLIAMENTARY AUTHORITY

All meetings shall be conducted in a manner that will allow the fullest possible participation by all members. In the event of a dispute, Robert’s Rules of Order, newly revised, shall be the parliamentary authority governing the meetings of the SPP RSC Board of Directors and all committees, subject to the laws of the state where the SPP RSC is incorporated, the Articles of Incorporation, these Bylaws, and any special rules of order adopted by the SPP RSC.

ARTICLE XI - OPEN MEETINGS

The Annual Meeting and all meetings of the SPP RSC Board of Directors and subordinate committees and work-groups shall be open meetings, except that discussion of commercially sensitive, legal, and personnel issues may be conducted in closed session. For the purposes of these Bylaws, open meeting means:

(a) Notice of the time, place, and purpose of the meeting, as provided in Articles III and IV, shall be made available to the public, through printed or electronic means, provided however, that the agenda for any annual, regular, or special meeting may be amended up to three (3) calendar days prior to the meeting date, as long as the amendment does not involve a change to the Bylaws or otherwise affect the substantive rights of Members.

(b) Minutes of the SPP RSC Board of Directors and subordinate committee meetings shall be made available to the public, through printed or electronic means, as soon as practical.

(c) The public may attend all open meetings of the SPP RSC.

(d) The SPP RSC Board of Directors may provide for participation by telephone or electronic means.

ARTICLE XII- AMENDMENTS

Except as otherwise stated herein, these Bylaws may be amended by a two-thirds vote of a quorum at the Annual Meeting and any regular meeting of the SPP RSC Board of Directors, provided that the proposed amendment(s) must have been included in the notice of the meeting in which such changes were to be considered.

Exceptions to two-thirds voting requirement: Any amendment(s) to Article I, § 3; Article IV, § 9 or Article VIII shall require the unanimous vote of the entire Board of Directors.

ARTICLE XIII- EXECUTIVE DIRECTOR
1. EMPLOYMENT. The SPP RSC Board of Directors may select an Executive Director. Where an Executive Director is hired, the SPP RSC Board of Directors shall determine the terms and conditions of the employment of the Executive Director. Thereafter, the Executive Director’s employment may be terminated by a majority of all serving SPP RSC Directors.

2. RESPONSIBILITIES. If deemed necessary and appropriate, where an Executive Director is hired, the Executive Director shall be the chief executive of the SPP RSC under the supervision and day-to-day policy guidance of the President of the SPP RSC Board of Directors. The Executive Director shall be responsible for providing advice and assistance to the SPP RSC Board of Directors, the President and other officers, and any subordinate committees and work-groups; and shall be responsible for administering the operations of the SPP RSC. The Executive Director shall have such other powers and perform such other duties as may be provided by the SPP RSC Board of Directors. The Executive Director shall be an ex officio non-voting member of the SPP RSC Board of Directors.
April 13, 2007

Re: Proposed Revisions to the SPP Travel Policy and Bylaws

Dear Name:

Attached please find red-lined versions of the SPP Travel Policy and SPP Bylaws containing the proposed revisions outlined below:

Travel Policy

1. Extension of the deadline for submission of expense reimbursements from thirty (30) to sixty (60) days on pages 1 and 3; and
2. Replacement of “and their delegates assigned to specific task forces and working groups” with either of two options presented in the comment field at the top of page 1.

Bylaws

1. Insertion of “Electronic Voting” as Paragraph 9 of Article IV – Board of Directors on page 5; and
2. Insertion of a “Delegated Authority” as Paragraph 5 of Article IX – Fiscal Responsibilities of the SPP RSC Board of Directors on page 8.

Sincerely,

Leslie E. Dillahunty
Vice President, Regulatory Policy
Travel Policy

The Southwest Power Pool Regional State Committee (“RSC”) will reimburse RSC members (and their delegates assigned to specific task forces and working groups) and RSC associate members (hereinafter severally and jointly referred to as “Member(s)”) for all fair and reasonable expenditures incurred by Members when conducting RSC business. It is intended that Members should neither lose nor gain money as a result of reimbursement.

1. Travel expenses must be submitted on the RSC expense reimbursement form within thirty (30) days after the conclusion of the travel. Receipts are required for all expenses.

2. The RSC expense reimbursement form must be signed by Member seeking reimbursement and in the case of an assigned delegate, by the individual state Commissioner assigned to the RSC.

3. While traveling and away from home, Members are expected to use good judgment when incurring expenses for lodging, meals, transportation, etc. RSC will reimburse business related mileage at the rate approved by the IRS. Reimbursement will be for mileage claimed due to travel to business location and return.

4. Members are responsible for making their own arrangements for transportation, lodging and car rentals. All accommodations should be purchased as far in advance as possible to obtain available discount fares/rates. All air travel is to be booked at the lowest accommodating fare.

5. Lodging reservations should be made at mid-priced establishments, when available. If a Member is attending a meeting or function being held at a specific facility, then reservations may be made at that facility.

6. The RSC will not accommodate advances for travel expenses; the RSC will only reimburse expenses after the fact with supporting documentation and approval as specified in this policy.

7. If a spouse or family member accompanies a Member on a business trip for non-business reasons, the family member’s travel expenses are not reimbursable.
Travel Guidelines

These numbers are provided as guidelines and are based on historical averages. Members are expected to use their best judgment while traveling.

Price Guidelines:
1. Airfare - $500 roundtrip within the SPP footprint
2. Hotel - $130/night
3. Meals - $45/ day
4. Car Rental - $70/day
5. Parking - $10/day
6. Tips & Gratuities – 15% tip for meals, 10% tip for cab fare, $1 per bag for baggage handling
Expense Reimbursement Policy

This policy is intended to identify reasonable, necessary and customary business expenses, which are eligible for reimbursement. Southwest Power Pool Regional State Committee ("RSC") participants eligible for reimbursement include RSC members (and their delegates assigned to specific task forces and working groups) and RSC associate members (hereinafter severally and jointly referred to as “Member(s)"

Business Mileage – Members will be reimbursed for all mileage incurred while using a personal vehicle for business. The Member will be reimbursed at the standard IRS mileage rate.

Personal Auto Use on Company Business – If a Member requests use of a personal vehicle in lieu of air travel, reimbursement will be made at the approved reimbursement rate for the most direct mileage to and from the business destination unless round trip air travel is less expensive. When this occurs, the round trip air travel cost will be reimbursed instead.

Mileage will be reimbursed at the then current IRS mileage rate. This expense is to be turned in on an expense account (within sixty (60) days) with the number of miles and the purpose of the trip.

Rental Cars, Taxis, Bus Fares, tolls, etc. – Reimbursement will be made for transportation while on RSC business, including transportation to and from airports and transportation to and from local businesses. Members are expected to use cost effective methods. The standard rental automobile will be a mid-size sedan.

RSC Meals – Members will be reimbursed for meals under the following circumstances:

- When out of town on business, the reasonable costs of the Member’s meals will be reimbursed.
- Business meals will be reimbursed when business is discussed and the Member documents the business purpose and who attended.

Lodging – Members will be reimbursed for lodging expenses incurred while on RSC business.

Meetings - The following are guidelines for a meeting the RSC might incur.

1. Lunch – plan for $25/ person
2. Continental Breakfast – plan for $10/person
3. Afternoon Break – plan for $150/total
4. Beverages – plan for $12/person
5. Meeting Room (<20 people) - $250/day
6. Meeting Room (>20 people) - $650/day
7. Supplies (<20 people) - $350/day
8. Supplies (>20 people) - $700/day
9. A/V Equipment
10. Conference Phones
11. Internet Access
12. Teleconference : 25 ports/2 hr. meeting

Receipts are required on all expenses.

Reimbursement will be approved per this policy. Periodically, reimbursements will be reviewed by the RSC officers for compliance with this policy.
# Southwest Power Pool
## Transmission Project Tracking
### Second Quarter, 2007: Base Plan Upgrades

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<th>Area</th>
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<td>Jan-07</td>
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<td>KCPL</td>
<td>Line - Tomahawk - Bendix 161 kV</td>
<td>Dec-06</td>
<td>$528,600</td>
<td>Blue</td>
<td>Jan-07</td>
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<td>WERE</td>
<td>Multi - HEC - 43rd &amp; Lorraine - Tower 33 69 kV</td>
<td>Dec-06</td>
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<td>Blue</td>
<td>Jan-07</td>
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<tr>
<td>WERE</td>
<td>Device - Clearwater 138 kV</td>
<td>Dec-06</td>
<td>$1,000,000</td>
<td>Blue</td>
<td>Jan-07</td>
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<td>WERE</td>
<td>Device - Udall 2 69 kV</td>
<td>Dec-06</td>
<td>$525,000</td>
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<td>Jan-07</td>
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<td>Line - NE Enid - Glenwood 138 kV</td>
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<td>OKGE</td>
<td>Line - Razorback - Short Mountain 69 kV</td>
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<td>Jan-07</td>
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<td>$41,711,741</td>
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<td>WERE</td>
<td>Line - Kansas City - Plaza Drive 138 kV</td>
<td>Apr-07</td>
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<td>WERE</td>
<td>Line - Snyder 69 kV</td>
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<td>Red</td>
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<td>AEPW</td>
<td>Line - Golden Plain - Gatz 69 kV</td>
<td>Jun-07</td>
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<td>Red</td>
<td>Jan-07</td>
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<td>Line - Hesston - Golden Plain 69 kV</td>
<td>Jun-07</td>
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<td>Red</td>
<td>Jan-07</td>
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<td>WERE</td>
<td>Line - HTI Junction - Circleville 115 kV</td>
<td>Jun-07</td>
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<td>AEPW</td>
<td>Line - Koss Lee - Oak Hill #2 138 kV</td>
<td>Jun-07</td>
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<td>Red</td>
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<td>MIPU</td>
<td>Line - Lake Road to Industrial Park 161 kV</td>
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<td>Blue</td>
<td>Jan-07</td>
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<td>WFEC Line - Wind Farm - Mooreland 138 kV</td>
<td>Jun-07</td>
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<td>SWPS XFR - Artesia 115/69 kV</td>
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<td>SWPS XFR - Carlbad Int 115/69 kV</td>
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<td>WERE XFR - County Line 115/69 kV</td>
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<td>SWPS XFR - Hale Co 115/69 kV</td>
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<td>SWPS XFR - Kress 115/69 kV</td>
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<td>SWPS XFR - Terry Co 115/69 kV</td>
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<td>GRDA XFR - Stilwell City 161/69 kV</td>
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<td>WFEC Line - Bradley - Rush Springs 69 kV</td>
<td>Dec-07</td>
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<td>WFEC Line - Elmore - Wallville 69 kV</td>
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<td>OKGE Line - Richards - Piedmont 138 kV</td>
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<td>WERE Device - 3rd &amp; VanBuren 115 kV</td>
<td>Jun-08</td>
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<td>Jan-07</td>
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<td>SWPS Device - Bowers 69 kV</td>
<td>Jun-08</td>
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<td>AEPW Line - Bann - Kings Highway 69 kV</td>
<td>Jun-08</td>
<td>$50,000</td>
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<td>MIPU Line - Blue Springs - Duncan Road 161 kV</td>
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<td>WERE Line - Coffeyville - CRA 69 kV</td>
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<td>WFEC Line - Hamoni Butler-Morewood 69 kV</td>
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<td>AEPW Line - Linwood-McWillo 138 kV</td>
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<td>WFEC Line - Sayre - Morewood 138 kV</td>
<td>Jun-08</td>
<td>$12,000,000</td>
<td>Jan-07</td>
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<tr>
<td>EMDE Line - Sub 167 - Riverton - Sub 406 - Riverton S 69 kV</td>
<td>Jun-08</td>
<td>$20,000</td>
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<td>AEPW Multi - Fayetteville 69 to 161 kV conversion</td>
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<td>$21,000,000</td>
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<td>SWPS XFR - Cochran 115/69 kV</td>
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<td>$2,750,000</td>
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<td>SWPS Note 13</td>
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<td>WFEC XFR - Ft Supply 70 MVA</td>
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<td>OKGE XFR - Knob Hill 138/69 kV</td>
<td>Jun-08</td>
<td>$1,834,568</td>
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<td>SWPS XFR - Mustang Sta N. 230/115 kV</td>
<td>Jun-08</td>
<td>$3,000,000</td>
<td>Jan-07</td>
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<td>SWPS XFR - NE Hereford 115/69 kV</td>
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<td>$1,750,000</td>
<td>Jan-07</td>
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<td>AEPW Line - Alumax Tap - Bann</td>
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<td>AEPW Line - South Shreveport - SW Shreveport 138 kV</td>
<td>Jun-10</td>
<td>$110,000</td>
<td>Jan-07</td>
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<td>MIDW Multi - Knoll - Hays - Vine 115 kV</td>
<td>Jun-10</td>
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<td>EMDE Multi - Riverdale - Ozarks 161 kV</td>
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<td>AEPW Device - Hobart 69 kV</td>
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<td>AEPW Line - 36th &amp; Lewis - 52nd &amp; Delaware Tap</td>
<td>Jun-16</td>
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<td>AEPW Device - Broken Arrow Water 69 kV</td>
<td>Jun-17</td>
<td>$550,000</td>
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</table>

| Total: | $172,687,668 |

2008

2009+

$16,998,000
2007, Second Quarter: Base Plan Upgrades

Project Notes:

SWPS Comment - Note 1 - XFR - Bailey Co 115/69 kV - Projected in-service April 2007.


SWPS Comment - Note 3 - Device - San Andress Sub 115 kV - Needs further analysis - Seminole project may mitigate - also not SWPS substation, owned by UE.

SWPS Comment - Note 4 - XFR - Artesia 115/69 kV - Needs 69 kV study - new load in area. Autos ok until 2017 w/ switching.

SWPS Comment - Note 5 - XFR - Carlsbad Int 115/69 kV - Need 69 kV study - generator may defer, new load may require 115 kV. No switching available.

SWPS Comment - Note 6 - XFR - Crosby Co Int 115/69 kV - Studies will be conducted to further analyze 69 kV system - alternate solution will likely alleviate overload.

SWPS Comment - Note 7 - XFR - Curry Co Int 115/69 kV - Requires 3rd 40 MVA auto. SWPS does not agree with this recommendation. Will study conversion of 69 kV distribution to 115 kV.

SWPS Comment - Note 8 - XFR - Gaines Co Int 115/69 kV - Studies will be conducted to further analyze 69 kV system - alternate solution will likely alleviate overload.

SWPS Comment - Note 9 - XFR - Hale Co 115/69 kV - Transformer on order.

SWPS Comment - Note 10 - XFR - Kress 115/69 kV - Transformer on order.

SWPS Comment - Note 11 - XFR - Lubbock East 115/69 kV - Transformer being ordered.

SWPS Comment - Note 12 - XFR - Terry Co 115/69 kV - Transformers recently delivered. In svc by 11/2007

SWPS Comment - Note 13 - XFR - Cochran 115/69 kV - Transformer being ordered.

SWPS Comment - Note 14 - XFR - NE Hereford 115/69 kV - Studies will be conducted to further analyze 69 kV system - alternate solution will likely alleviate overload.

AEP Comment - Note 1 - Switch & CT by 6/2008

AEP Comment - Note 2 - In Service by 6/2008

AEP Comment - Note 3 - In Service by 6/2008

WERE Comment - Note 1 - Equipment on order, In Service by 12/07

WERE Comment - Note 2 - Equipment on order, In Service by 12/07

WERE Comment - Note 3 - Scheduled in Service by 6/08

WERE Comment - Note 4 - Load transferred off tertiary

WFEC Comment - Note 1 - Further load shift analyses needs to be conducted to identify mitigation

WFEC Comment - Note 2 - Scheduled in svc by 12/07
2007, Second Quarter: Base Plan Upgrades

Project Status Changes:

OKGE's 'Line - Westmoore-Pennsylvania 138 kV' project has been removed from the Base Plan Upgrade list, as it has been identified as a reliability project driven by the TO's planned Earlywine project. The RTO Reliability Need Date date has shifted from October 2007 to October 2009, so an amended Letter of Authorization has been issued.

OKGE's Line - Etowah-Tribbey 69kV project has been removed from the Base Plan Upgrade list, as it has been cancelled due to a modeling correction.

WERE's 'Multi - Hutchinson 115 kV conversion' project has been removed from the Base Plan Upgrade list, as it has been identified as an Existing Facility under the Tariff.
Overview –
Five Objectives of Order No. 890

1. Improve transparency and consistency by providing greater consistency in ATC calculation;
2. Reform transmission planning requirements;
3. Reform certain portions of the pro forma OATT that permitted utilities to discriminate against new merchant generation;
4. Provide greater transparency in transmission service by granting greater access to information; and
5. Reform areas of the OATT that have been the source of disputes over the past 10 years.

Order No. 890 Deadlines

- May 14 – Effective date of Order No. 890 and non-RTO compliance filings due
- May 29 – Planning Strawman must be posted on the web site
- June 6 & 7 – At conclusion of SEARUC Meeting, FERC/State Regional Technical Conference
- September 11 – Transmission Providers must file changes to Attachment C (ATC)
- October 11 – OATT compliance filing for RTOs
  1. RTOs may demonstrate how tariff variations are consistent with or superior to Order No. 890.
  2. Transmission Owner members of RTOs must make conforming compliance filings.
Coordinated, Open and Transparent Transmission Planning

Order No. 890 adopted 9 principles for transmission planning:

1. Coordination
2. Openness
3. Transparency
4. Information Exchange
5. Comparability
6. Dispute Resolution
7. Regional Participation
8. Economic Planning Studies
9. Cost Allocation for New Projects

Planning strawman webex – April 27, 2007

Consistency and Transparency of ATC Calculations – Attachment C

Transmission Providers must amend their Attachment C to:

- Provide a detailed description for calculating firm and non-firm ATC;
- Identify which NERC-approved methodologies it employs (e.g., contract path, network ATC, or network AFC);
- Work with NERC to modify ATC-related reliability standards;
- Work with NAESB to develop business practices that complement NERC's standards;
- Provide specific mathematical algorithms;
- Give process flow diagrams;
- Provide definitions of ATC components; and
- List the databases used.
Non-Rate Terms and Conditions – Roll Over Rights

- Roll over rights now for service agreements of five year or longer.
- One year notification requirement to exercise roll over right.
- New roll over right paradigm effective when FERC accepts the regional planning documentation.

Non-Rate Terms and Conditions – Redispatch Rate Transparency

Transmission Providers must post on OASIS the following redispatch information (if redispatch is provided):

- Its monthly average cost of redispatch for each internal congested transmission facility or interface over which it provides planning redispatch or reliability redispatch;
- The high and low redispatch cost for the month for each of these same transmission constraints; and
- Internal constraint or interface data for the month if any planning redispatch or reliability redispatch is provided during the month, regardless of whether the transmission customer is required to reimburse the transmission provider for those exact costs.

Transmission Providers must work with NAESB to develop OASIS functionality and business practice standards.
Non-Rate Terms and Conditions – Processing Transmission Studies

- Must track and post performance metrics related to processing and completion of transmission studies. (~26)
- Must notify the Commission if it processes more than 20% of the studies outside the due diligence deadline for two consecutive quarters.
- Subsequent to notification, additional performance tracking and posting requirements.
- Subject to operational penalties ($500/day) if it completes 10% or more of the studies outside of the due diligence deadlines in two subsequent quarters.
- Must distribute the penalties to customers.
- Tracking and reporting obligations begin May 14.

Non-Rate Terms and Conditions – Planning Redispatch and Conditional Firm Service

- Generally, SIS must identify (1) redispatch options, including an estimate of the redispatch cost, and (2) conditional firm service (CFS) options, under certain conditions.
  1. CFS curtable either for a specified number of hours in a year or upon the occurrence of specifically identified system contingencies (secondary network priority).
  2. Providers with real time energy markets need not offer conditional firm service.
- RTOs must work with customers to facilitate third party redispatch obligations.
- Must implement mechanisms and business practices within 180 days (Sept. 11).
Order No. 890's Major Impacts on SPP

- Conforming the SPP Tariff to the Order 890 *pro forma* Tariff. An administrative matter of significance.

- Significant task to comply with the Order’s rules concerning the posting of information that is not now required to be posted; i.e. performance metrics for aggregate studies for short and long-term service, redispatch costs (if any).

- Planning standards strawman within 75 days and participation in the associated FERC/State Regional Technical Conference on planning, including developing a coordinated planning process with neighboring transmission providers.

- Monitoring the NERC/NAESB process that will incorporate new reliability standards for outcomes that may impact SPP’s ATC methods. SPP must post its ATC methodology on its OATT.

- Commitment to address conditional service needs in SPP’s energy imbalance market notwithstanding Order No. 890’s directive that RTOs with energy markets need not offer conditional firm service.