Southwest Power Pool
BOARD OF DIRECTORS MEETING
July 20, 2000 Called Meeting
Embassy Suites Outdoor World – Dallas/Ft. Worth Airport

- A G E N D A -

WEDNESDAY, JULY 19
6 to 7:30 p.m. – Reception – La Buena Vida Room

THURSDAY, JULY 20
7:30 a.m. – Continental Breakfast – Pheasant Ridge V
8 to noon – Meeting

1. Administrative Items .... Gary Voigt
   a. Call to Order, Introductions, Receipt of Proxies
   b. Approval of May 11, 2000 Meeting Minutes

2. Secretary's Report .... Nick Brown
   a. Interim Action
   b. Follow-up Items from 5/11/00 Meeting
   c. Filling Board Vacancies

3. RTO Working Group Report .... Mel Perkins/David Christiano

4. Entergy Transco Proposal .... Frank Gallaher

5. Future Meetings .... Gary Voigt

6. Adjournment .... Gary Voigt

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Doubletree Hotel at Warren Place – Tulsa, Oklahoma
May 11, 2000

- Summary of Action Items -

1. Approved minutes of the February 14, 2000 meeting as modified.

2. Approved the 1999 Audit prepared by Deloitte & Touche LLP.

3. Approved the 2000 funding of $400,000 for the SPP Retirement Plan and $152,400 for the retiree medical coverage of SPP employees retiring at the Normal Retirement date.

4. Approved the following modifications to SPP's Savings Plan: 1) changing the list of trustees for the SPP Savings Plan in Section T (1) "Investment" of the plan document to "President", "Director, Corporate Services", "Human Resources Generalist", and "Human Resources Systems Analyst"; 2) modifying the loan administrator to the positions of "Human Resources Generalist" and "Human Resources System Analyst" in Section T (1) (b) (iii); and 3) modifying the Savings Plan in Section K, "Entry Requirements - Service Required to become an Active Member" to state that "Service is Not Required."

5. Supported the inclusion of an Entergy transmission company under the SPP RTO and approved formation of policy and technical teams to develop specific details by July 7, 2000 for Board of Directors consideration and subsequent filing with the FERC.

6. Approved Coordinated Generation Interconnection Procedures be filed with FERC as an attachment to the SPP Regional Transmission Service Tariff.

7. Approved submittal of an informational filing with the Public Utility Commission of Texas regarding SPP's intent to seek independent operator status within the non-ERCOT portion of Texas.

8. Approved filing the Next Hour Market Tariff Provisions developed by NERC to enable the offering of Next-hour Market Service by the summer 2000 peak period. SPP will submit such a filing seeking implementation with a one-day suspension from the date that SPP is operationally able to implement per Security Working Group approval.

9. Approved changes to Criteria 3.0 – Regional Transmission Planning Modifications; Criteria 7.3 – Under-Frequency Load Shedding and Restoration Modifications; and Criteria 10 – Emergency Communications Modifications.

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Doubletree Hotel at Warren Place – Tulsa, Oklahoma
May 11, 2000

<u>Agenda Item 1 - Administrative Items</u>

SPP Chair Mr. Gary Voigt called the meeting to order at 8:00 a.m., thanked everyone present for attending, called for a round of introductions and referred to a full agenda (Agenda – Attachment 1). The following Board members were in attendance or represented by proxy:

Mr. Gene Argo, Midwest Energy, Inc.;
Mr. David Christiano, City Utilities of Springfield, MO;
Mr. Steve Wilson proxy for Kim Casey, Dynegy Marketing & Trade;
Mr. Jimmy Crosslin, Oklahoma Corporation Commission;
Mr. Gene Anderson proxy for Harry Dawson, OK Municipal Power Authority;
Mr. Michael Deihl, Southwestern Power Administration;
Mr. Jim Eckelberger;
Mr. Tom Grennan, Western Resources;
Mr. Quentin Jackson;
Mr. Kevin Smith proxy for Trudy Harper, Tenaska Power Services Company;
Mr. Tom McDaniel;
Mr. Bill Gipson proxy for Myron McKinney, Empire District Electric Company;
Mr. John Oxendine;
Mr. Stephen Parr, Kansas Electric Power Cooperative;
Mr. J. M. Shafer, Western Farmers Electric Cooperative;
Mr. Harry Skilton
Mr. Al Strecker, proxy for Mr. Steve Moore, OG+E;
Mr. Larry Sur;
Mr. Gary Voigt, Chair, Arkansas Electric Cooperative Corp.;
Mr. Robert Zemanek, Central and South West Corp.; and
Mr. John Marschewski, Southwest Power Pool, Inc.

There were 39 persons in attendance representing 19 members, 8 guests and 1 regulatory agency (Attendance List – Attachment 2). In addition to the directors, the following persons were also in attendance: Mr. Dick Dixon (WERE); Messrs. Mel Perkins and Melvin Bowen (OKGE); Mr. Rick Henley (Jonesboro); Messrs. Frank Gallaher, John Zemanek and Steve Owens (ENTR); Messrs. Dave McNabb, Gary Fulks, Chris Bolick (AECI); Mr. Richard Verret (AEP); Mr. Gene Reeves and Ms. Tracy Hannon (SWPA); Mr. Rick Veatch (Utilicorp); Mr. Larry Wells (CLECO); and Messrs. Frank Royster and Nick Brown and Ms. Susan Skipper (SPP Staff). The Secretary received five proxy statements (Proxies – Attachment 3).

Mr. Voigt referred to draft minutes of the February 14, 2000 Meeting (2/14/00 Meeting Minutes - Attachment 4) and asked for necessary corrections or a motion for approval. Mr. Brown noted a suggested deletion of the words (page 3, last sentence in paragraph

2 under Agenda Item 4) "*and with Mr. Deihl abstaining*". Mr. Zemanek motioned that the minutes be approved as modified. Mr. Deihl seconded this motion, which passed unopposed.

Mr. Voigt referred to the 1999 Audit prepared by Deloitte & Touche LLP (1999 Audit – Attachment 5). Mr. Marschewski motioned that the audit be approved as distributed. Mr. Zemanek seconded the motion and it passed unopposed.

Agenda Item 2 – Employee Benefits Working Group Report & Recommendations

Retirement Plan and Retiree Medical Coverage Expense

Mr. Voigt asked Mr. Shafer to present the EBWG report. Mr. Shafer stated that the EBWG was recommending 2000 funding of $400,000 for the SPP Retirement Plan and $152,400 for the retiree medical coverage of SPP employees retiring at the Normal Retirement Rate (EBWG Recommendation – Attachment 6). Mr. Shafer motioned that the Board of directors approve the EBWG recommendation. Mr. McDaniel seconded the motion and it passed unopposed.

401(k) Plan Changes

Mr. Shafer then summarized recommended changes to SPP's 401(k) plan that were also being recommended by the EBWG. These changes included: 1) changing the list of trustees for the SPP Savings Plan in Section T (1) "Investment" of the plan document to "President"," Director, Corporate Services", "Human Resources Generalist", and "Human Resources Systems Analyst"; 2) modifying the loan administrator to the positions of "Human Resources Generalist" and "Human Resources System Analyst" in Section T (1) (b) (iii); 3) modifying the Savings Plan in Section K, "Entry Requirements - Service Required to become an Active Member" to state that "Service is Not Required." (EBWG Recommendation – Attachment 7). Mr. Shafer then motioned that the Board of Directors approve the EBWG recommendation. Mr. Deihl seconded the motion, which passed unopposed.

Agenda Item 3 – Entergy Transco Proposal

Mr. Voigt then asked Mr. Frank Gallaher to present Entergy's RTO/Transco partnership proposal (Entergy Transco Proposal – Attachment 8) for Board of Directors consideration. Mr. Gallaher presented several slides (Entergy Slides – Attachment 9) summarizing proposed terms and conditions suggested as an appendix to SPP's membership agreement, that would allow a transco, including Entergy, to operate within the structure, and under the oversight, of the SPP RTO (Entergy Terms & Conditions – Attachment 10). Mr. Gallaher concluded his presentation by stating his belief that Entergy participation in SPP under the RTO/Transco partnership model would benefit regional security coordination, add merit to SPP's RTO structure and size, and provide another viable business option to SPP transmission owners. Following considerable discussion, Mr. Gary Voigt convened the Board of Directors in executive session at

10:02 a.m. CDT, pursuant to Section 4.6.5 of SPP's bylaws, to candidly discuss the proposal.

Mr. Voigt reconvened the meeting in open session at 10:48 a.m. CDT and announced that the Board of Directors supports the inclusion of a transco including Entergy under the SPP RTO and directed that policy and technical teams be formed to develop specific details by July 7, 2000 using Entergy's proposal as a working document, for Board of Directors consideration and subsequent filing with the FERC.

Mr. Christiano asked for a specific vote on an initial main motion submitted during executive session that had been successfully amended and approved without opposition. Mr. Voigt called for this vote, which passed with one vote cast in opposition (Mr. Christiano).

Mr. Voigt noted that the Staff (with member support) had been directed to develop as soon as possible a white paper analyzing the various pros and cons of Entergy's proposed terms and conditions.

Agenda Item 4 – Commercial Practices Committee Report & Recommendations
Mr. Voigt asked for the Commercial Practices Committee (CPC) report.

Generation Interconnection Procedures
Mr. Dick Dixon reported that the Transmission Assessment Working Group completed initial development of generation interconnection procedures last year to standardize practices within SPP and sent them to the Regional Tariff Working Group (RTWG) for finalization and regulatory formatting necessary for a FERC filing (Generation Interconnection Procedures – Attachment 9). Mr. Dixon noted that the RTWG addressed some remaining issues and approved a final version of the procedures for CPC and Board consideration. These final revisions were based on the most recent FERC orders related to generation interconnection procedures. Mr. Shafer motioned and Mr. Grennan seconded that the Coordinated Generation Interconnection Procedures be approved and filed with FERC as an attachment to the SPP Tariff. This motion passed unopposed.

PUCT Information Filing
Mr. Brown, on behalf of CPC Chair Ms. Trudy Harper, reported that the Market Settlement Working Group (MSWG) has been developing a request for proposal for commercial and operational systems necessary to support scheduling and settlement processes and market based ancillary services necessary for RTO and retail access implementation. Mr. Brown noted that SPP has worked diligently to keep the Public Utility Commission of Texas PUCT informed of progress and that the MSWG believed a part of this effort should include an informational filing (PUCT Information Filing –

Attachment 10). Mr. Smith motioned and Mr. Zemanek seconded that the Board of Directors approve the submittal of an informational filing with the Public Utility commission of Texas regarding SPP's intent to seek independent operator status within Texas. This motion passed without opposition.

Next Hour Market Tariff Modifications

Mr. Brown, again reporting on behalf of Ms. Trudy Harper, then stated that the FERC has conditionally accepted a filing of the North American Electric Reliability Council (NERC) proposing that transmission providers who choose to do so may voluntarily provide Next-hour Market Service (NHM Service) to their customers (Next Hour Market Tariff Modifications – Attachment 11). Mr. Brown stated that, at the request of NERC, the CPC approved filing a set of standard revisions for adoption into the SPP regional tariff. Mr. Brown noted that SPP participation will require modification of transaction tagging and reservation processes and if approved, SPP will submit such a filing seeking implementation with a one-day suspension from the date that SPP is operationally able to implement per Security Working Group determination.

Mr. Dixon informed the Board of Directors that, due to limited time, SPP's normal due process of Regional Tariff Working Group consideration had been bypassed in CPC consideration, and that transmission owners had not had adequate time to review the proposal for negative impacts on transmission revenue. As such, Mr. Dixon suggested accepting the modifications with a one-year sunset provision, thereby allowing a review period prior to permanent modification. Mr. Smith questioned the need for the sunset provision given the number of changes that SPP has made to the tariff since implementation. Mr. Grennan then motioned and Mr. Deihl seconded that the recommended filing be approved with the one-year sunset provision. This motion passed without opposition.

Agenda Item 5 – Engineering & Operating Committee Report & Recommendations

Mr. Voigt then asked Mr. Mel Perkins to present the Engineering & Operating Committee report and recommendations.

Regional Transmission Planning Criteria Modifications

Mr. Perkins stated that Criteria 3.0 was reviewed and modified based on new requirements of NERC such that SPP and its members maintain an acceptable level of compliance in accordance with NERC's current Standards and Measures. Mr. Perkins also noted that the TAWG moved criteria related to equipment rating in a new criteria section, including both generation (Section 2.4.3) and transmission (Section 3.6) equipment ratings. Mr. Perkins stated that the Engineering and Operating Committee recommends the Board of Directors approve the revised Criteria 3.0 (Criteria 3.0 – Attachment 12) as presented to replace the existing Criteria 3.0 and that Section 3.6, Rating of Transmission Circuits, and Section 2.4.3, Rating of Generation Equipment, are renumbered and moved to Section 12.1 and 12.0, respectively with no content changes.

<u>Under-frequency Load Shedding & Restoration Criteria Modifications</u>

Mr. Perkins stated Criteria 7.3 was reviewed based on additional requirements of NERC, again so that SPP and its members maintain an acceptable level of compliance in accordance with NERC's current Standards and Measures. Mr. Perkins stated that NERC policy requires that each Region develop an under-frequency load shedding program as identified in SPP's Criteria Section 7.3.3.1. Mr. Perkins reported that the first technical assessment of the program, in the form of a regional simulation study, will be completed by SPP no later than June 1, 2001 and the Engineeing & Operating Committee is recommending that the Board of Directors approve the new Criteria 7.3, Under-frequency Load Shedding And Restoration (Criteria 7.3 – Attachment 13), and direct the development of SPP's Coordination of Under-frequency Load Shedding Program.

<u>Emergency Communications Criteria Modifications</u>

Mr. Perkins then reported that the Engineering and Operating Committee, in preparation for Y2K, requested and were granted by the Board of Directors on May 13, 1999, budgeting to purchase and implement satellite phones for use as backup to the public switched network. Mr. Perkins noted that the Security Working Group formed a Telecommunications Task Force to both implement these phones and to develop a protocol for phone usage. Mr. Perkins stated that SPP Criteria 10 was modified to require the use of the satellite phones in place of the high frequency radios that have been in place for over ten years. Mr. Perkins stated that the Engineering and Operating Committee recommends that the Board of Directors approve the revised Criteria 10 (Criteria 10 – Attachment 14).

In response to questions, Mr. Brown noted that the Engineering & Operating Committee approved each of these recommendations without opposition. Mr. Zemanek motioned that all three criteria modifications be approved as recommended by the Engineering & Operating Committee. Mr. Parr seconded this motion and it passed unopposed.

<u>Agenda Item 6 – Policy Report & Recommendations</u>

Mr. Voigt then asked Mr. Brown to brief the Board of Directors on several pending policy issues. Mr. Brown referred to a summary of regulatory activities (Chronological Sequence Table – Attachment 15) and specifically noted that SPP's RTO filing was placed on FERC's May 17, 2000 agenda. Mr. Brown then noted that settlement documents had been filed on May 5, 2000 related to the items set for hearing in SPP's comprehensive tariff filing. Mr. Brown noted the expensive nature of this hearing process for such a minor issue – even though SPP was fortunate enough to reach early agreement to settle the issues. Mr. Brown stated that he would be mentioning this in future discussions with FERC commissioners and staff and encouraging restraint in items being set for hearing.

Mr. Brown also discussed a Staff recommendation concerning member rebate of funds not presently supported by tariff administrative fee income (Staff Recommendation – Attachment 16). Mr. Brown discussed SPP assuming the debt, for which tariff customers would bare 80 percent of the carrying charges and members would bare 20 percent. Mr. Brown noted that Staff is in the process of negotiating terms and conditions for such a loan from Firstar and believes a successful outcome is eminent. Mr. Voigt asked if the Staff considered applying the member's cost of capitol to cover carrying charges. Mr. Brown stated that he had not considered this because several members stated a desire to not carry the costs at all. Messrs. Skilton and Oxendine questioned why this issue was not noted in the audit and Mr. Skilton asked for an auditor's opinion of SPP assuming this debt prior to action. Mr. Brown stated that these issues would be resolved and the item placed on the agenda for the next meeting.

<u>Additional Items</u>

Following discussion, Mr. Marschewski motioned that the Board of Directors meet next in Dallas on July 20, 2000. Mr. Grennan seconded this motion, which passed without opposition. The specific location will be announced at a later date.

Mr. Voigt then recognized Mr. Grennan, who read a proposed resolution thanking Mr. Bob Zemanek for his contributions to and support of Southwest Power Pool (Resolution – Attachment xx). Mr. Grennan motioned that the Board of Directors approve the resolution. Mr. Sur seconded this motion, which passed unanimously. Mr. Voigt directed the Staff to suitably print and frame the resolution for presentation to Mr. Zemanek and also to post the resolution on SPP's internet homepage for all to see.

<u>Agenda Item 7 – Adjournment</u>

With no further business, Mr. Voigt thanked everyone for their participation and adjourned the meeting at 12:02 p.m. CDT.

Nicholas A. Brown, Corporate Secretary

Southwest Power Pool
STAFF
Report to the Board of Directors
July 20, 2000

Background

At the May 11, 2000 meeting of the Board of Directors, SPP Corporate Secretary Nick Brown presented a Staff recommendation concerning SPP assuming the member debt of funds not presently supported by tariff administrative fee income. In so doing, tariff customers would bare 80 percent of the carrying charges and members would bare 20 percent. Several directors questioned why this issue was not noted in the audit and asked for an auditor's opinion of SPP assuming this debt prior to action. Staff is continuing to evaluate options for future Board consideration but have received the auditor's response to these questions.

Response

1. Why was the member debt not footnoted in the 1999 SPP Audit?
   a. They are aware of the manner in which SPP views the tariff shortfall and how we are keeping track of the funds owed to our members. However, they did not comment on this because the shortfall is not a true liability, that is, any shortfall repayment or recognition of the debt is not addressed in a SPP document thereby verifying the debt and recognizing the repayment procedure. If there is such a document then we should provide it to Diane.

2. What is Deliotte and Touche opinion of SPP assuming the debt and showing it as a liability?
   a. They offer opinions on the application of accounting principals as they relate a proposed transaction that has accounting implications and how these transactions would be accounted for. They do not offer opinions on whether a future transaction is a sound business decision.

Diane Branch of Deliotte and Touche

Southwest Power Pool
Report to the Board of Directors
July 20, 2000

Background

SPP President John Marschewski has received resignation letters from SPP directors Bob Zemanek of Central and South West Corp. and Steve Moore Oklahoma of Gas & Electric Co. Per SPP Bylaws Section 4.5, if a vacancy occurs, the Board of Directors will elect an interim director representing the same Membership category to serve until a replacement director is elected at the next Meeting of Members to fill the vacancy for the unexpired term.

Nominations

SPP Chair and Vice Chair, Gary Voigt and Tom Grennan recommend and nominate Richard Verrett of American Electric Power and Al Strecker of Oklahoma Gas & Electric Co. to fill the respective vacancies.

Action Requested: Approve recommendation

Southwest Power Pool
REGIONAL TRANSMISSION ORGANIZATION WORKING GROUP
Report to the Board of Directors
WORKING DRAFT – July 12, 2000

BACKGROUND

On December 30, 1999 Southwest Power Pool (SPP) filed a petition with the Federal Energy Regulatory Commission (FERC) seeking recognition as a Regional Transmission Organization (RTO) pursuant to FERC Order 2000 (Docket No. EL00-39-000). On May 17, 2000, FERC denied SPP's proposal finding that it required modification to meet the standards necessary for recognition as an RTO and the order provided guidance regarding certain aspects of SPP's filing. SPP leadership immediately decided not to seek rehearing and committed to developing a filing that meets FERC expectations.

In response to FERC's order and other Board of Directors action regarding Entergy's RTO/Transco partnership proposal presented to the Board at their May 11, 2000 meeting, SPP Chair Gary Voigt established the Regional Transmission Organization Working Group (RTOWG) reporting to the Board of Directors. The charge of this working group is to develop and recommend to the Board of Directors organizational documents necessary for SPP to receive FERC recognition as a RTO pursuant to their Order No. 2000 and order on SPP's initial filing. During this process, the RTOWG also acted as the 'policy team' directed to be formed by the Board of Directors to develop necessary modifications to SPP's documents to include a transco under the SPP RTO as conceptually proposed by Entergy. This group was formed under the Board of Directors because the subject involves both commercial and engineering and operating issues and time precluded having the group report to two committees. A conference was envisioned to seek member and public comment on a product prior to final Board approval.

As with all SPP research and development activities a working group was formed that was well representative of the membership and contained necessary expertise to accomplish its assigned task. Though participation in SPP meetings is open to all interested parties, additional Transmission Customer members were added after the first meeting and were balanced by the addition of an equal number of Transmission Provider representatives. The RTOWG roster consists of:

Transmission Providers	Transmission Customers
Mel Perkins, OKGE	David Christiano SPRM
Mike Desselle, CESW	Ricky Bittle, AREC
J. M. Shafer, WEFA	Rick Henley, Jonesboro
Henry Janhsen, SWPS	Bob Reilley, Coral
Dick Dixon, WERE	Kurtz Stowers, PGE
Jim Sherwood, SWPA	Christine Ryan, ETEC
Ron Kite, KCPL	Betsy Carr, Dynegy

Nick Brown, SPP

RECENT ACTIVITIES

Meeting With FERC

SPP representatives met with FERC commissioners and staff on May 31 to gain additional guidance on SPP's goal of achieving FERC recognition as an RTO and questions specifically focused on SPP's collaborative process, operational control, governance, and scope. Representing SPP were Mel Perkins and David Christiano (as RTOWG co-chairs), Dick Dixon (as chair of the Regional Tariff Working Group), and John Marschewski, Nick Brown and Pat Bourne (SPP Staff). Steve Owens and Kim Despeaux of Entergy also participated. Meetings were held with Commissioners Breathitt and Massey, and with Commissioner Hebert's legal advisor Joshua Rokach. The group also met with several FERC staff representatives including Dan Larcamp, Kevin Kelly, Shelton Canon, Bill Longnecker and Leon Lowery. FERC staff encouraged primary focus on regional scope, seams issues, and the Entergy partnership proposal. The commissioners and staff minimized SPP's proposed governance structure as an issue. As a result of the meeting, all SPP participants agreed that pre-filing conferences will be absolutely essential in the future in order to provide accurate and complete information to the FERC staff and commissioners about SPP filing.

Collaborative Process

The RTOWG met initially on June 6 and 7 with 40 persons in attendance and quickly agreed to the following collaborative plan of action: identification of major issues; formation of sub-teams to work in an open and self directed fashion in addressing the major issues; hosting public workshops as necessary to gain additional information and understanding; and presenting a final product to the Board of Directors on July 20 for consideration. FERC's order on SPP's initial RTO filing directed "SPP to conduct a more thorough evaluation of those aspects of its proposal not addressed in this order. In so doing, SPP can address Intervenors' relevant concerns during any collaborative process it adopts." The RTOWG co-chairs established an objective for the RTOWG that a SPP RTO filing is made without protests, and a second objective that, if a protest is made, that the issue had at least been considered by the RTOWG. To this end, the co-chairs made a plea at each and every RTOWG meeting to get issues on the agenda.

Following identification of issues, the RTOWG concurred with formation of the following sub-teams to respond to the various outstanding issues:

- Governance – RTOWG,
- Section 203 Filings – Staff/Counsel,
- Tariff (zones/expansion) – Regional Tariff Working Group,
- Settlement – Market Settlement Working Group,
- Public and Regulatory Education – RTOWG leadership,
- Seams – At large participation led by Mike Apprill,
- Congestion Management – At large participation led by Ricky Bittle,
- RTO/Transco Partnership – At large participation led by Gene Anderson, and
- Scope & Configuration – At large participation led by Michael Desselle.

Email exploder lists were created for the RTOWG and each issue sub-team for dissemination of ALL correspondence and were open to self-subscription by any and all interested parties. RTOWG meeting minutes and ALL working documents were distributed via the RTOWG and sub-team exploder lists and were posted for public viewing and access via SPP's homepage at www.spp.org. FERC representatives were formally invited to participate in ALL related activities and all parties that protested SPP's initial RTO filing were also invited to participate.

In considering recommendations before the RTOWG, straw votes of concurrence were taken from all participants prior to official votes by the RTOWG members to insure that any and all concerns were considered. To ensure completely open participation, Staff agreed to not to utilize RTOWG voting records in arguments before the FERC. The RTOWG met a second time on June 20 with 46 persons attending to hear initial sub-team reports and strawman votes of concurrence were taken indicating that the sub-teams were proceeding in the right direction.

As congestion management is of critical importance in designing the SPP RTO, the Congestion Sub-Team hosted a public conference on June 19 with over 75 persons attending to hear presentations on various alternatives from industry experts including Larry Ruff of Energy & Economic Consulting, Bill Hogan of Harvard University, Narasimha Rao of Tabors Caramanis & Associates, and Ed Cazalet of Automated Power Exchange.

Summary of Meetings

The following items briefly describe meeting events related to RTOWG efforts:

- RTOWG meetings on June 6-7, 20 and July 19,
- Education Sub-Team teleconference calls on June 9, 12 and 16,
- Partnership Sub-Team meetings on June 14-15, 19, 29 and July 17,
- Seams Sub-Team meetings on June 7 and 19 and two-hour teleconference calls on June 12, 15, 30 and July 7,
- Congestion Sub-Team meetings on June 7 and 19 and over two-hour teleconference calls on June 27 and July 5,
- Market Settlement Working Group meeting on June 5, and
- Regional Tariff Working Group meeting on June 28 and four-hour teleconference calls on June 16 and 22,

ANALYSIS

Sub-Team reports are contained in separate sections that follow. Several issues were specifically debated and resolved by the RTOWG rather than making an assignment to a self-directed sub-team.

Governance

FERC Order 2000 requires that RTO be governed in a fair and non-discriminatory manner, independent of undue influence by any individual or group of market participants. SPP's RTO filing proposed maintaining its newly approved and implemented structure for the Board of Directors. The FERC order on SPP's RTO filing instructed SPP to use the collaborative process to address intervenors' independence concerns prior to submitting its modified RTO filing. The existing governance structure was discussed at the first RTOWG meeting and a plea was made for any issues to be raised during the meeting or distributed via the RTOWG email exploder. No issues were raised during the entire RTOWG deliberation process with SPP's current governance structure being maintained in the context of SPP's RTO filing. A straw vote of all participants on maintaining SPP's current governance structure in SPP's RTO filing indicated no opposition and a motion to maintain SPP's current governance structure in SPP's RTO filing passed without opposition.

Section 203 Filings

FERC Order 2000 requires transmission owners to turn over operational control of their transmission facilities to an RTO. The transfer of operational control of FERC-jurisdictional transmission facilities occurs via a FERC filing under Section 203 of the Federal Power Act. SPP's initial filing proposed that SPP's administration of service over transmission owner facilities be governed by its membership agreement, which formed an agency relationship with owners for SPP's tariff administration responsibilities. SPP proposed this contractual approach, as opposed to Section 203 filings, to maintain similar treatment of its jurisdictional and many non-jurisdictional transmission owners. FERC's order on SPP's initial RTO filing found that an RTO proposal that provides for full transfer of operational control of jurisdictional facilities will require Section 203 filings. This issue was not assigned to a sub-team, but Staff and Counsel were directed to develop a proposal concerning Section 203 filings for FERC-jurisdictional transmission owners. The following two-point proposal was presented for RTOWG consideration.

1. *203 Applications* – FERC's SPP RTO order makes clear that all FERC regulated public utilities owning transmission to be transferred to SPP's operational control must file 203 Applications as part of an RTO proposal. Regional Transmission Organizations, Order No. 2000, III FERC Stats. & Regs., Regs. Preambles ¶ 31,089, at 30,944 n.5. These public utilities are the investor owned utilities plus any other transmission owners that are no longer exempted from FERC regulation under Section 201 of the Federal Power Act such as Coops that have paid off their RUS loans. A standardized 203 Application should be developed as the reasoning for approval generally will be the same in all cases; i.e., the transfer of control is necessary to carry out FERC's statement of the public interest as reflected in Order 2000. Each transmission owner will need to develop a list of facilities or maps showing the facilities covered by the 203 application. These 203 applications should be filed together with the RTO filing so that there is no question that operational control is being transferred. See Section 35.34 (d).

2. *Membership/Agency Agreements* – All transmission owners will continue being covered by a Membership Agreement. The Membership Agreements currently in effect will be used with a few modifications. For non-FERC jurisdictional entities, the contractual relationship will be maintained as no explicit 203 application will be filed for those entities. SPP, however, will file those agreements with FERC which will treat those agreements as it sees fit. Those non-FERC jurisdictional entities also should specify which facilities are being transferred to SPP's control. The changes to be considered to the Membership Agreements include:
   - Eliminating the use of the term "agent" and instead imposing fiduciary obligations,
   - Explicitly stating that all transmission owners are transferring operational control of the designated transmission facilities to SPP,
   - Providing SPP with approval authority for transmission maintenance,
   - Making clear that SPP will have exclusive authority for receiving, confirming and implementing all interchange schedules,
   - Adding in statements that these membership agreements are intended to transfer to SPP all operational control required by Order 2000,
   - Whether any changes need to be made to the filing rights provisions in the membership agreement, and
   - Other miscellaneous changes to comply with Order 2000 such as the agreement to study within two years whether the division of operational control is working.

A straw vote of all participants on the proposed process for Section 203 filings with SPP's RTO filing and modifications of the membership agreement indicated no opposition. A motion to proceed with the proposed process to guide specific modifications to SPP's tariff and membership agreement for use in SPP's RTO filing was approved by the RTOWG without opposition.

Market Settlement

FERC's Order 2000 requires the RTO to be provider of last resort for ancillary services and to operate a real-time balancing market accessible to all transmission customers. In its initial RTO filing, SPP submitted that its regional tariff supported SPP as provider of last resort of all ancillary services and that the real-time balancing market was being evaluated in a retail open access context and had not been developed as of the time of the filing. The Market Settlement Working Group (MSWG) was chartered on March 22, 2000 with the responsibility to coordinate the changes necessary to the wholesale scheduling, settlement, and ancillary services processes necessary to implement retail open access and RTO operations under Order 2000. The MSWG provides oversight and direction to SPP in the modification of scheduling, settlement and ancillary services processes and computer systems. As such, the RTOWG assigned the MSWG the responsibility of developing the settlement process that SPP would propose in an RTO filing.

In response to SPP's initial RTO filing FERC directed SPP to develop an approach to operate a real-time balancing market by the time it files its modified RTO proposal. FERC requires the proposal to include a thorough and detailed justification of whether customers pay for all imbalances or only imbalances within a specified band, including an explanation of how the filing party proposes to overcome any disadvantages of the market approach selected. FERC will require SPP to have, at the very least, a process in place whereby such development will occur and to file details of that process, including a timeline for implementation. On June 29, 2000, the MSWG sent a Request for Proposal (RFP) to vendors. The RFP was for the acquisition of systems to support scheduling, ancillary service bids and dispatch, and settlement. Bids are expected by July 31, 2000. The following processes were approved without opposition by the MSWG for recommendation to the RTOWG to be used in SPP's RTO filing.

The real-time balancing market is based on hour-ahead bids to the RTO from resources. These bids are voluntary and will be stacked by price. Upon selection performance instructions for energy imbalance service will be sent from the RTO directly to the resource. Regulation instructions will be sent from the control area operators directly to the resource. Schedules of all load and resources committed for the load will be submitted to the RTO on a day-ahead and hour-ahead basis. The RTO will prepare a forecast and make this information and the gap between its forecast and the market committed resources through scheduling available to the market participants on an hour-ahead basis.

The settlement function accounts for all energy by using the net input into the grid as a control number. The end-use is calibrated to the net input and compared to the schedule data and the difference, positive or negative, is settled based on the market clearing price of the energy imbalance market. The market participants may mitigate the impact of energy imbalance services through the independent contracting for energy imbalance resources and offering those resources to the RTO for operational dispatch.

The advantage of settling on all energy imbalances is that the market-clearing price can be used for settling both the supply of and the use of energy imbalance. Settling on only imbalances outside a bandwidth would require billing parties using energy imbalance at a different rate that the suppliers of energy imbalance resources. This would reduce the transparency of the market, especially to participants who might be both users and suppliers into energy imbalance services. This approach is also consistent with the settling of inadvertent energy between control areas. All market participants would see the same price, set through the deployment of market bid resources, during the settlement interval. Another advantage of settling all imbalance at the market clearing price is that the RTO can neither under nor over-recover.

The process detailed above allows the market to establish the price used in the spot balancing market and renders price transparency to all market participants supplying or utilizing energy imbalance services within a settlement period. This also recognizes SPP's role as an active facilitator of the real-time balancing market and the availability of the resources under that market to all market participants.

Congestion Management

In its Order 2000, the FERC set out specific requirements regarding an RTO's development and implementation of a congestion management system. It must ensure that market mechanisms are used to manage transmission congestion. Order 2000 at (§35.4(j)(2)(i)) states the following:

> The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions. The Regional Transmission Organization must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant.

The FERC also provided the RTO with significant flexibility to experiment with various market approaches to manage congestion. A number of such approaches were enumerated and discussed in Order 2000. Although the FERC did not prescribe a specific mechanism, it found that " . . . some approaches appear to offer more promise than others." "As we stated in our order approving the PJM ISO and reiterated in the NOPR, markets based on locational marginal pricing and financial rights for firm transmission service appear to provide a sound framework for efficient congestion management." Yet, it also stated: "While our experience has shown that, in specific situations, some approaches to congestion pricing appear to have advantages over others, we have not yet identified one approach as being clearly superior to all others. Furthermore, the Commission recognizes that an RTO's choice of a congestion pricing method will depend on a variety of factors, many of which may be unique to that RTO. Therefore, we will allow RTOs considerable flexibility to propose a congestion pricing method that is best suited to each RTO's individual circumstances."

In its initial RTO filing SPP offered Section 33 of its regional tariff and the related Attachment K (Redispatch Procedures and Redispatch Costs) as the means initially to satisfy the market based congestion management system RTO requirement. The FERC order noted that Order 2000 provides an RTO up to one year to finalize market mechanisms to manage congestion, as long as effective protocols for managing or preventing congestion are in place at start-up. It then found that, although SPP has a congestion management plan in place, it is not fully developed and directed it to use the collaborative process to address intervener concerns prior to filing a modified RTO proposal. Pursuant to this direction from the Commission, the Regional Transmission Organization Working Group (RTOWG) commissioned the formation of this Congestion Sub-Team to manage this collaborative effort. There are several time constraints that must be addressed. The FERC, in Order 2000, expects a market-based solution for congestion management to be implemented within one year of initial operation of the

RTO. The Arkansas and Texas legislation requiring open access will allow retail choice as early as 1/1/2002.

At the June 19 congestion management symposium three methods of congestion management were discussed. They were Locational Marginal Pricing (LMP), Zonal with physical rights (ZPR) and Flow-based Congestion Management (ZCM). Although variants of these three methodologies have been discussed, no other significant methodology has been advanced. The discussions have not lead to a consensus opinion. Because of the amount of information presented to the Congestion Sub-Team, it has not yet voted on the proposals. To date Entergy has sponsored LMP, Coral has sponsored ZPR and Dynegy has sponsored FCM. Each proponent is capable of pointing out flaws of the other systems.

The following description of the three methods is taken from a comparison of congestion management mechanisms provided by Larry Ruff.

Locational Marginal Pricing - The RTO operates an integrated dispatch/spot market process that determines market-clearing energy prices at every node based on the actual security-constrained dispatch. These prices are used to settle energy imbalances, to price congestion for both spot and contract transactions and to settle point-to-point "financial transmission rights" (FTRs) that are allocated and/or auctioned by the RTO. When it is efficient and practical to do so, ancillary services are procured and priced by the RTO as part of this same integrated dispatch/pricing process.

Zonal with Physical Rights - The RTO determines the dominant transmission constraints that are "commercially significant," defines the "flow factors" indicating how injections at each node affect flows across each "flowgate," and allocates/ auctions "flowgate rights" (FGRs) for each flowgate. Market participants trade energy and FGRs among themselves and then submit balanced bilateral schedules that are consistent with their FGRs and the flow factors. The RTO then uses some market process(es) to redispatch generation in real time to deal with residual congestion and contract imbalances. The costs of meeting any constraints not represented by the few flowgates are "socialized" or spread across the market. To the extent practical, ancillary services are procured in separate and even non-RTO markets.

Flow-based Congestion Management - The RTO delineates pricing zones within which LMP differences are not deemed "commercially significant" and then defines and allocates/auctions "physical transmission rights" (PTRs) on each of the interfaces between zones. Spot (unscheduled) trading may be allowed at the uniform, RTO-determined settlement price within each zone, but interzonal trades must be scheduled with the RTO consistent with PTRs held by the traders. The RTO manages intrazonal congestion and interzonal flows by making constrained on/off payments to generators redispatched out of merit. To the extent practical, ancillary services are procured in separate and even non-RTO markets.

In order to provide some reference material the following are provided as attachments to this report:

Attachment No. 1 - Comparison of congestion management mechanisms by Larry Ruff
Attachment No. 2 - Comparison of congestion management schemes by Narasimha Rao
Attachment No. 3 - Questions about congestion management by APX
Attachment No. 4 - Questions and answers for understanding Flow-based scheduling by APX
Attachment No. 5 - Coral's response to questions by David McNabb (AECI)
Attachment No. 6 - Questions about Congestion Management by Narasimha Rao
Attachment No. 7 - SPP staff straw man

During the telephone discussions on June 27th the following goals for a congestion management system were discussed:

1. Current generation and transmission assets, as well as future asset additions should be used efficiently. A congestion management system should be developed that allows generation and transmission solutions to congestion to compete.
2. Real-time price signals are necessary for proper operation.
3. There should be a fair allocation of risk.
4. The congestion management system used should result in the lowest possible cost to end-use customers.
5. Information must be provided that allows the market to develop forward price forecasts. “Ex Ante” pricing is necessary.
6. There must be price certainty. “Post Ante” pricing should be minimized, if not eliminated.
7. System implementation must be timely.
8. The congestion management system must be market based.
9. The congestion management system must be flexible and responsive to market need.
10. The congestion management System must integrate with the market settlement system.
11. The congestion management system must be compatible with the anticipated implementation of retail competition in the various jurisdictions contained within the SPP.
12. The congestion management system must be operationally efficient and administratively feasible.
13. The congestion management system must be seamless.
14. The congestion management system should provide for participation by load. Proper price signals should be conveyed to the end user.
15. The congestion management system should be designed in such a way that it is difficult to game.

Attachment No.2 provides one assessment of how congestion management schemes met each of these goals.

The sub-team leader provides the following observations for RTOWG and Board of Directors consideration:

1. No one likes Transmission Loading Relief (TLR)
2. There is not a perfect congestion management scheme. It is not possible to simultaneously provide absolute price certainty and absolute certainty of delivery. All three of the proposed methods require the ability to "socialize" some cost.
3. Congestion management will not provide the incentive for building transmission. Congestion management will provide information regarding price differences between areas.
4. In order to provide liquidity in markets that trade physical rights, the physical rights must be traded at market prices not at cost.
5. Physical rights models function best with a minimum number of constraints.
6. Actual implementation of any of the three options will depend on the rules that are adopted.
7. Seams will continue to cause problems. Because the SPP is a part of the eastern interconnection, loop flow issues/impacts must be dealt with as part of the market design.

A two-day meeting in Dallas will be proposed to the CMS in order to understand the concerns of interested parties and begin the process of developing future direction. Interested parties will be invited to present their concerns about the application of specific methods using detailed examples of the problems they have experienced or expect. These presenters also will be asked to demonstrate how their preferred method addresses those concerns. At the same time, the CMS will discuss how the congestion management system alternatives discussed address the distinctive needs of the SPP. For example, discussions should address how zones would be developed for the SPP and whether, and to what extent, retail settlement zones relate to congestion zones. Additionally, this meeting will be used to start the process of developing estimates of cost and time required for implementation of the selected methodology. At the end of the meeting, straw votes will be taken on these fundamental issues in order to narrow the options under evaluation and to set future direction.

The Congestion Sub-Team recommends that SPP’s RTO filing contain a more extensive description and defense of SPP’s existing redispatch procedures as well as a discussion of activities and progress made toward completion of new market-based procedures as of the date of the filing.

UtiliCorp Proposals

During early RTOWG deliberation, UtiliCorp presented specific proposals for RTOWG consideration. These proposals are presented below, each followed by responses unanimously endorsed by straw votes and unanimously approved by vote of the RTOWG.

A. SPP should seriously consider merging with the new proposed MAPP/MISO organization. The key reasons are that MISO already has ISO recognition and very little extra work is expected for SPP to obtain FERC approval. Several Commissioners at FERC talk about the idea instate as a small number of large regional RTO’s. State Commissions and market players continue to complain about the seams problems in the Midwest. The main oppositions that we have heard from SPP about the concept are the added cost, and time delay. Since SPP’s RTO was rejected, the time delay issue is much less significant. Regarding cost, the administrative fee figures we have heard from MISO are within three cents of what SPP has proposed. UtiliCorp believes that SPP will ultimately merge with MISO at some point, so tackling this issue up front will save the members a lot of time and money.

SPP RTOWG Response:

On February 14, 2000, the Southwest Power Pool Board of Directors voted to continue current efforts to aggressively pursue FERC recognition as an RTO without MISO consolidation at this time. This was not a vote to indefinitely terminate discussions; therefore the Board is at liberty to open these negotiations at any time. Realizing that SPP consolidation with the MISO could at some future point be beneficial to the SPP membership, the RTOWG recommends that the status of the MISO development be monitored. The RTOWG feels that any new pursuit of consolidation with the MISO is not within its current scope.

B. A second alternative would be an organization like what Commissioner Massey proposed at the Members meeting on April 26, 2000. In his keynote address, the Commissioner suggested that SPP consider an RTO structure similar to ComEd’s ITC concept under the MISO. In other words, subgroups under MISO that could be made up of SPP transmission systems. Under this concept, SPP could have more than one subgroup. One subgroup could include transmission owners where control is transferred with a section 203 filing while another subgroup could include a transco or ITC. This concept has merit because it can leave most of the SPP reliability council, security coordinator and many of the other organizational structures and systems intact. If desired, the SPP subgroup could continue a governance to resemble what SPP has now with the added step of final approvals by the MISO independent BOD. This concept will allow SPP to leverage more of what it may want as an RTO organization from FERC and MISO because it creates the larger RTO that they both would like to see. As an example, the ComEd ITC proposal to operate under the MISO obtained FERC’s favor even though the MISO filed comments opposing some elements.

SPP RTOWG Response:

This is a unique proposal that could interest the SPP membership. More details would need to be presented before determining the merit. If Utilicorp and others are interested in pursuing this type of organizational structure, the RTOWG recommends that a proposal be presented to the SPP BOD. In development of the proposal, the RTOWG would welcome the opportunity to review the documents after the RTO filing is completed.

C. The final option is for SPP to develop reciprocity and seamless operation with adjacent utilities and regional entities. UtiliCorp believes this step will need to be done by SPP as a minimum to address the scope and configuration issues the FERC included in the order rejecting the SPP RTO. UtiliCorp also believes that to address these issues, much of the time and effort to accomplish A or B above will have been addressed any way. UtiliCorp would rather see the SPP pursue either of the other options first, but if the majority desire otherwise, then we would support option C as a minimum effort of what needs to be done for SPP to comply with FERC's comments.

SPP RTOWG Response:

The RTOWG agrees with the Utilicorp recommendation. The Seams issues are within the scope of and very important to the RTOWG. It will be critical to successfully address seams resolution in the new RTO filing. A Seams subteam has been formed from the RTOWG and is chaired by Mike Apprill of Utilicorp to investigate and provide solutions for the filing.

Scope and Configuration

In its order on SPP's initial RTO filing, the FERC found "… that SPP's regional configuration is inadequate based on this record." FERC directed SPP to address the following concerns in its new proposal: 1) the extent to which SPP's operations will be impacted by the absence of its former members situated at the boundaries, 2) whether it is feasible – or even possible – to include them in the proposed RTO, and 3) specific procedures and rate structures for operation with adjacent entities and whether it is feasible for SPP to join with other groups engaged in forming RTOs in the region.

No specific sub-team meetings were held aside from responding to Entergy's (a former member) RTO/Transco partnership proposal, but SPP Staff and SPP members made substantial contact with SPP's neighbors to address their concerns. Several face-to-face meetings were held with Associated Electric Cooperatives (a former member) personnel and their representatives attended and actively participated in RTOWG and sub-team meetings. SPP has three members that previously had their transmission facilities under the regional tariff, but later withdrew those facilities for various reasons. Two of these three members, UtiliCorp and CLECO, actively participated in RTOWG and sub-team meetings. Southwestern Public Service, a SPP transmission-owning member that had previously not placed its facilities under the regional tariff has since done so. Contact was also specifically made with TVA and Southern Company to invite their participation in SPP's development process and to understand any concerns they may have.

Indeed, while SPP has attempted to solicit interest in its RTO by neighboring transmission owners and to address any of their stated concerns, SPP membership and RTO participation is still a voluntary action on their part.

Seams

In its Order 2000, the FERC set out specific requirements regarding an RTO's scope and configuration. It stated that an RTO should be of sufficient configuration to encompass contiguous geographic areas and highly interconnected portions of the grid, taking into account useful existing regional boundaries. In the context of this boundaries discussion, intervenors pointed out, and the Commission agreed, that it is important that there be integration and coordination among RTOs, particularly with respect to reliability and market practices, and that scope of a particular RTO becomes less important if it is part of an RTO group that has eliminated the negative effects of seams.

By virtue of the significance of comments on this issue, the Commission was persuaded to add Interregional Coordination (Minimum Function 8) to the explicit list of RTO minimum functions set out in the RTO NOPR. In its discussion of this minimum function, the Commission required that an RTO develop mechanisms to coordinate activities with other regions, whether or not such regions are included in another RTO. Such RTO must explain how it will pursue integration of reliability and market interface practices, thereby ensuring that market activity is not limited due to different practices within the adjoining regions.

In its initial RTO proposal SPP specified that Section 2.1.1(e) of its Membership Agreement obligates it to continue to coordinate with neighboring regional organizations. Moreover, it committed to continue being active in addressing seams issues. At that time, SPP had already engaged in negotiations with both the Mid-Continent Area Power Pool ("MAPP") and the Midwest ISO for the purpose of addressing these issues and had, during these discussions, addressed parallel path flow problems external to it.
In its discussion of SPP's scope and configuration, the FERC emphasized the requirement that an RTO must create a seamless trading area and enumerated intervenor concerns that SPP had not specified the mechanisms by which it will coordinate operations with other regional utilities. It required SPP to address " . . . what specific procedures and rate structures SPP will implement when coordinating its operations with adjacent utilities and regional entities; and whether it is feasible for SPP to join with other groups engaged in forming RTOs in the region."

The Seams Sub-Team identified seams issues for SPP to consider when addressing FERC's concerns in a revised RTO filing. The main FERC concerns that the Seams

Sub-Team is addressing are in regard to the need for procedures and rate structures to coordinate SPP's operations with adjacent transmission providers and regional entities. To the extent that there are different tariffs or differences within a tariff, the seams issues may occur with Transcos within SPP as well as other transmission providers or other RTOs that interconnect with SPP. This document will refer to the terms "RTO" or "Transmission Provider" (TP) as covering all of these categories. The Seams Sub-Team developed a set of goals to achieve in addressing these issues, which are identified below. The Seams Sub-Team has identified the adjacent entities across the seams that will be invited to address the seams issues with the RTOWG Seams Sub-Team.

The Seams Sub-Team identified the following list of goals to be met for seams recommendations that SPP would advocate in its future RTO filing:

1. The seams recommendations should provide added value to market participants and should address FERC's concerns about the lack of procedures and rate structure to coordinate SPP's operation with adjacent transmission providers and regional entities to facilitate efficient transmission with adjacent transmission utilities and regional entities and create seamless trading areas.
2. The seams recommendations must be operationally efficient and administratively feasible. Attempt to meet the requirements of Order 2000 with present systems and minimal increase in the SPP and market participants administrative cost.
3. The seams recommendations must be consistent with or be shown to be superior to FERC Open Access Tariff requirements. Develop an RTO proposal that meets or exceeds Order 2000 or FERC's guidance from SPP's order. The RTO proposal should deter the exercise of participants market power.
4. The seams recommendations should be compatible and equitable with the processes, procedures and tariffs of adjacent transmission utilities and regional entities to meet Order 2000 requirements to expand regional configuration and to address gaps in the SPP geographic coverage.
5. The seams recommendations should address transactions that affect adjacent transmission utilities and regional entities to insure equitable compensation to address lack of control of inter-tie facilities of adjacent transmission utilities for the purpose of improving interregional coordination.

The Seams Sub-Team recommends the following principles for development of specific tariff language:

a. Provide One Stop Shopping as an option to the present procedure.
b. Provide tariff reciprocity with specific procedures and rate structures to coordinate with adjacent utilities and regional entities.

c. Provide pricing methodologies for transactions across multiple regions that reduce or eliminate pancaking while at the same time minimize revenue shortfall and unequal revenue distribution.
d. Include a protocol development process to improve and expand the Planning, System Expansion and Outage Coordination with adjacent utilities and regional entities.

A series of slides have been prepared and attached to this report that describe proposed implementation details.

Reservation/Oasis
The present arrangement for a transaction between two regions requires a minimum of accessing two reservation systems to obtain separate OASIS numbers for the same transaction. In addition there are different standards for the lead-time required to make reservations. The ideal situation is to have "One Stop Shopping" on one reservation system to make the request and that all analysis would be done for all regional transmission groups involved at the same time with approval or rejection done at that time. The process should include having to generate only one OASIS number.

One Stop Shopping (OSS) procedures and protocols will need to be identified to deal with multiple tariffs while still maintaining present mechanisms for those not wanting OSS. The general idea is to offer OSS as an alternative to the existing process. The Midwest ISO Appendix I has language on protocol development processes between the Midwest ISO and the ITC that may provide guidance on how to apply a similar process between two RTO's.

> The following is the referenced language from the Midwest ISO Appendix I:
> *Section 16. OPERATING PROCEDURES AND PROTOCOLS*
>
> *16.1 The ITC and the Midwest ISO shall cooperate and use their best efforts to develop the necessary operating procedures and protocols to allow timely start-up of the ITC pursuant to this Appendix I. Any disagreement shall be resolved pursuant to dispute resolution. Once such procedures and protocols have been developed, either through agreement or after dispute resolution, the Midwest ISO shall post such procedures and protocols on its website.*

Proposed Actions: Provide in the SPP RTO filing, the OSS option for any other RTO or TP that is interconnected with SPP.

Scheduling/Tagging
This issue is similar to the Reservation seams issue. When individual schedules are submitted there should be provision of "One Stop Shopping" with only one tag. In

addition standards are needed for such features as the time deadline on when tags can be submitted.

The same would apply as for Reservation/OASIS above. Key issues yet to be determined include whether source or sink RTO or TP would administer the OSS process and what scheduling fees would be collected (just source and sink RTO's/TP's or all RTO's/TP's involved) and would there be a discount or premium for this service?

Proposed Actions: Same as Reservation/OASIS above and to address scheduling fees question.

Loop Flow

The Sub-Team did not see this as an issue, if congestion management, TLR and Security Coordination seams issues are properly addressed. TLR is presently being standardized by NERC. The method to calculate ATC, TTC should also be standardized.

Proposed Actions: See the sections on Congestion Management and Planning and System Expansion.

Tariff

a. Transmission Pricing

There should be one transmission rate for transactions across regions that would be made available at the time the reservation is made. There may be different methodologies to determine the rate but the total price should be provided to the requesting party. Methodologies should be explored that reduce or eliminate pancaking while at the same time minimize the impact of revenue shortfall and unequal distribution of revenues.

The SPP/MISO collaborative process is already discussing this issue and is considering alternate pricing proposals. The key issue is how to address revenue shortfall during the transition period before all load (wholesale and retail) is under the tariff. The Seams Subteam believes that some pricing approaches may be more appropriate during the transition period before all load is under the tariff and others may be better suited for the long term.

Nick Brown presented a straw man proposal at the FERC's RTO Workshop in Kansas City that has the customer paying the sink RTO rate with revenue to the sink RTO and a surcharge applied to load in the source RTO to cover foregone source RTO pt-to-pt revenue (Proposal 1). Another variation is to have the surcharge applied to all of the load in the sink RTO (Proposal 2) or some sharing between and source and sink RTO's (Proposal 3: 50/50 sharing). . Yet other proposals mirror the SPP tariff where the customer only pays the sink RPT zone rate with an agreed to allocation of revenues between the RTO's (Proposal 4 – revenue allocation between RTO's in proportion to

MW-mile impacts). Proposals with the surcharge concept may be better situated for a transition period. After extensive discussion on July 7 the Seams Subteam favored only further consideration of Proposals 3 and 4. Examples of this implementation have been developed and are included as an attachment to this report.

Other concepts may be more situated for long-term solutions such as one from Clair Moeller (NSP) presented at the SPP/MISO collaborative meetings with a three-component rate. This concept includes a source RTO rate, a sink RTO rate and a Highway rate. The Highway rate has mechanisms for distribution of the revenue to remaining zones in both RTO's. The Seams Subteam believes concepts like this should be explored for long term solutions, but would be too difficult to develop for the filing deadline.

Proposed Actions: The short term recommendation is have the Seams Subteam review the alternative rates, specifically Proposals 3 and 4, that address pancaked rates with the revenue shortfall issue and submit a recommendation to the RTWG for including in the proposed RTO filing that would serve as a transitional rate proposal for transactions between and through multiple reciprocating RTO's and TP's. A longer term action item is to review various pricing and revenue shortfall concepts that would apply when all load is under the tariff, forward the material to the RTWG, and ask them to address when they address formula rates.

b. Ancillary Services

The pricing for Ancillary Services should include a consolidated rate that would apply for transactions between and across multiple RTO's and TP's. Some regions require charges for Ancillaries like Var/Voltage while others do not. The key Ancillary Services that need to be addressed are Reactive Supply/Voltage Control (RSVC) and Scheduling.

In SPP, RSVC primarily represents the generation component of fixed cost for the TP's (transmission system fixed cost is typically included in the transmission rate). RSVC is also generally a small portion of the total transmission services. Presently, the rate for transactions sunk in the SPP is based on and paid to the sink zone. The rate for transactions out of or through SPP is the weighted average of all zones distributed back to the TP's. The SPP Scheduling service is normally based on transactions using a skip schedule and includes the source and sink control area fees.

Proposed Actions: The recommendation is for SPP to offer reciprocity on RSVC consistent with the ultimate treatment of the base rate for transmission service. The recommendation for Scheduling as part of reciprocity is to use skip scheduling from source to sink and the customer would pay the source and sink zones of both RTO's. This is consistent with SPP the transmission pricing concept since both zones would have cost associated with setting up the schedule.

c. Losses
Losses are different from other ancillaries in that they represent variable cost and are distance sensitive. In SPP customer pays sink zone losses and revenue goes to sink zone. The losses rate for transactions out of SPP is the weighted average of zones distributed back to the providers.

Proposed Actions: SPP needs to develop reciprocity procedures for losses similar to the transmission rate component for the filing. The Seams Subteam believes the loss charge should equal the sum of the loss charges for all the RTOs providing the subject service.

d. Administrative Charges
Typically these fees are cost based and justified by the RTO's and TP's. The coordination and consolidation of transmission services into "One Stop Shopping" may require additional up front cost to implement, but over time should reduce the on-going cost because duplication is being avoided. Regional tariffs should provide mechanisms to reflect ultimate reduced administrative fees. Regions could consider incentives in exchange for reciprocity. The administrative charge could be less for transactions across two regions with reciprocity versus two that do not.

Proposed Actions: For transactions across two or more RTO's, it is recommended that the customer should pay the sink RTO rate plus an additional charge equal to the sum of the administrative charge of all of the other RTO's in the contract path with such additional charge capped at five cents per megawatt hour. The sink RTO collects its sink fee and the adder is distributed to the other RTO's in the contract path.

Congestion Management
Ideally the analysis for identifying congestion and the procedures to relieve it should be standardized between adjacent regions and should be implemented jointly when effective. The method to calculate ATC, TTC should be standardized with standard timing requirements. A separate Subteam is addressing Congestion issues for SPP as an RTO, but the Seams Subteam believes it is important that the Congestion Management Subteam also needs develop procedures that will accommodate seams congestion.

Proposed Actions: Communicate to the Congestion Management Subteam to address appropriate seams issues as part of the Congestion Management for SPP as an RTO. Before the Congestion Management Subteam finalizes the congestion issues, the Seams Subteam should review and provide input. Included in the seams congestion issues should be features that address the seams elements of Planning and System Expansion.

Planning and System Expansion
Transmission planning and identification of system expansions should include impacts on adjoining regions. Reciprocity provisions need to include how to deal with tariff issues regarding upgrade cost and sharing of cost.

Proposed Actions: SPP should develop procedures and protocols for planning and system expansion with other RTO's. The process should include dealing with loop flow impacts, cost assignments and recovery of revenue requirements. Would language similar to what is developed for the RTO/Transco Partnership be appropriate?

Outage Coordination
Presently there is some information being exchanged on maintenance outages of equipment.

Proposed Actions: A full coordination of maintenance outages is required for proper security analysis. RTOs should assure that is accomplished through coordination between the appropriate Security Coordinators.

Regional and Individual Utility SEAMS
The Seams Subteam had identified several regions and transmission providers where the seams issues have an impact. It is recommended that discussions should be initiated with these groups to develop as much detail as possible on the seams issues and to include it in the SPP RTO filing. The Seams Subteam is identifying contact people within these organizations and will soon be initiating discussions. The plan is to use the existing SPP/MISO collaborative process for MISO and possibly MAPP. The regional group and transmission providers identified are:
1. MAPP
2. MISO
3. ERCOT
4. SERC
5. Entergy
6. AECI
7. Other former SPP Regional Tariff members
8. WSCC

Placement of Bundled Load Under Regional Tariff
An issue raised during early RTOWG debate was placement of transmission owner bundled retail load under the regional tariff to ensure equitable treatment of all transmission customers. This issue was not assigned to a sub-team, but Staff and Counsel were directed to develop an issue list concerning the placement of all load under the SPP regional tariff. The following issues were presented to the RTOWG:
- SPP can recover 100 percent of costs under Tariff,
- Schedule 1 charge will be substantially lower,

- Eliminates comparability arguments on this issue as all load would be under the same rules and therefore FERC should like it,
- Allows the design of transmission rates to fully recover transmission revenue requirements and can eliminate cost under-recoveries resulting from the elimination of pancaking,
- Makes it easier to argue at FERC for the direct assignment of new transmission facilities as FERC denied direct assignment for SPP and MISO based on comparability concerns; in contrast, it has allowed direct assignment of network upgrades for regions with all load under the Tariff such as California and PJM,
- Allows the full recovery of the costs of new transmission facilities by the transmission owner even without direct assignment as the costs can be rolled into rates and the owner would be fully paid the revenue requirements associated with that facility, and also would facilitate entities other than the SPP transmission owner's constructing the transmission facilities,
- Eliminates the need for transmission owners to maintain separate transmission tariffs assuming that all grandfathered load would be under the SPP Tariff,
- May eliminate grandfathering pancaking disputes - In a PJM order FERC required the elimination of pancaking caused by grandfathered agreements,
- Eliminates disputes on the portion of congestion uplift charges, maintenance costs, etc that should be recovered from bundled load,
- Should make it easier to argue for recovery of redispatch costs without caps on top of embedded cost rates because it would eliminate comparability issues,
- All scheduling will be under the SPP tariff so there will not be multiple schedulers,
- Allows transmission owners to take network service for all of their load, thereby avoiding point-to-point charges for purchases into their systems,
- State commissions may see this as an infringement on their jurisdiction as bundled retail load would be under a FERC tariff,
- There may be a problem of incompatibility with bundled retail rates as transmission owners would be paying SPP for network service (together with Schedule 1 charges) and receiving their revenue requirements - If a transmission owner pays more for transmission than it has embedded in retail rates, then it will face a cost recovery problem particularly if it is not able to adjust its retail rates,
- Schedule 1 costs would be paid for all load which could result in some companies paying more than they pay today though as noted above the level of the Schedule 1 charge will go down,
- Putting all transmission under a FERC tariff provides transmission owners with a better argument that the state must allow recovery of all of the increased costs resulting from the RTO, and
- Disrupts existing grandfathered agreements.

This issue has been further debated by the Regional Tariff Working Group with respect to tariff provisions on the transitioning of load from individual transmission owner tariffs to the regional tariff.

Entergy RTO/Transco Partnership

The Partnership Sub-Team systematically discussed and addressed each of the 23 points in Entergy's proposed term sheet for the transco/RTO partnership. At the current state of negotiations, ten points are characterized as "no disagreement noted;" seven points are characterized as "OK as modified and clarified for Board understanding;" and six points need more work to reach consensus. Troubling issues remain in two primary areas: congestion management (point 7), which is being addressed by the Congestion Sub-Team; and maintenance of two tariffs (points 4, 5, 8, 15 & 21). Several participants noted strong concern over the separate calculation of Available Transfer Capability or ATC. The following points are a result of negotiations to date:

This Proposal outlines the terms and conditions in a proposed Appendix to the Southwest Power Pool's ("SPP's") Membership Agreement that would allow a Transco including Entergy ("the Transco") to operate within the structure, and under the oversight, of an SPP RTO. This is referred to as a Partnership RTO structure.

1. *Basic Governance and Operational Responsibilities*. This proposal will allow the Transco to operate under the oversight of the SPP RTO. The SPP's role shall include (1) acting as regional Security Coordinator for the SPP and Transco systems; (2) coordinating with the Transco on the ATC and TTC calculations and methodologies; (3) fostering full and complete input by market participants into the Transco's policies; (4) overseeing a regional transmission expansion planning process; and (5) providing an appropriate forum for market monitoring and dispute resolution. The proposal should also prevent rate pancaking in the SPP's and Transco's regions. Transco shall have the option of participating on the SPP RTO Board of Directors on the same terms and conditions as all other SPP RTO Members. These provisions are currently set out in Sections 4.2 and 4.3 of the Southwest Power Pool Bylaws.

2. Because SPP will perform multiple roles under the Partnership RTO model, the staff structure and organization will be reviewed and appropriately modified to ensure non-discriminatory treatment of all parties with respect to RTO functions. The organizational structure will be designed to provide independence between the RTO functions: oversight, planning, security coordination and market monitoring, all of which will be performed by SPP, and the transmission provider and tariff administrator functions, which will be performed by SPP, by SPP non-Transco members, and by Transco. These changes are focused on complying with the objectives outlined in FERC Order No. 2000. In particular, the following functions will be separated with a code of conduct specifying the policies and procedures that must be followed in all business transactions between these functions:

a) Transmission provider and tariff administration functions. SPP will be a transmission provider and control area operator within the RTO territory, as will Transco. There should be a level playing field among all transmission providers, control area operators, and transmission users under the SPP RTO.

b) Regional coordination and planning functions. SPP will provide security coordination and regional planning functions for the entire RTO region. The security coordinator function should be clearly separated from the transmission provider and tariff administrator function. The separation of the security coordinator function may be achieved, at the election of the SPP Board, either through the use of a strict code of conduct or by organizational separation, in which case the security coordinator would report to the SPP Board of Directors, independently from the tariff administrator function. The code of conduct would strictly forbid the security coordinator from taking any actions in carrying out the duties and responsibilities of security coordinator that advantage the transactions over one transmission owners system over the transactions over any other transmission owners system.

c) Oversight functions. Under this proposal, SPP's oversight responsibilities include market monitoring and ADR. These functions will be carried out by a separate group of employees and managers reporting directly to the SPP Board. The Board may use an independent outside firm to assist in the monitoring activities. The scope of the monitoring function is described below in paragraph 16. It includes monitoring of the other functions of SPP, including security coordination.

3. *FERC Review and Approval of the Transco Proposal*. The Transco shall seek and obtain FERC approval to operate as a Transco under the SPP RTO..

4. *Transmission Tariff*. In the event that SPP and Transco agree to implement the same congestion management regime, the RTO shall administer a single tariff that will apply to transmission service within the SPP and Transco RTO. Transco will have control over those portions of the tariff that affect the commercial terms and conditions of transmission service over Transco's facilities. Transco shall possess the unilateral right, without receiving any SPP RTO approval, to make filings at FERC proposing rate or rate structure changes (including incentive rate structures) involving transmission charges for service to load within the Transco or transmission service that does not cross any of the SPP transmission operator facilities. Transco also retains the right to unilaterally make filings at FERC for the purposes of implementing new transmission services that are not contained in the RTO Transmission Tariff. Transco will provide SPP with a copy of any such filing 30 days prior to filing with FERC and will make reasonable efforts to resolve any issues regarding the new service prior to filing at FERC, but in no circumstances shall this extend beyond 45 days from the time SPP is provided a copy of the proposed filing. A detailed list of the pro forma tariff provisions that Transco will have the unilateral right to change through FERC filings will be developed and attached to this agreement as Appendix A.

The Transco will be responsible for conducting studies and scheduling transactions on the Transco's system and shall be the provider of last resort for ancillary services in accordance with FERC Order Nos. 888 and 2000. The SPP shall have real time access to the Transco's ATC and TTC calculations and shall coordinate with the Transco in developing a consistent method for calculation of ATC and TTC over the combined regions of SPP and Transco. Transco agrees to utilize the same model as used by SPP if SPP agrees to incorporate the VST model (Vacar, Southern, TVA) data and also agrees to work with Transco on the process, method and timing of updates to ensure that neither party's practices will invalidate the TTC/ATC calculations. If the Transco and the SPP cannot resolve a disagreement over an ATC or TTC calculation, then the SPP can submit that disagreement to the SPP's ADR process, provided that the Transco's calculation shall be binding during the pendency of the ADR proceeding.

5. *Transmission Rates*. In designing transmission rates, SPP and Transco agree that there shall be no pancaked rates for transmission service with respect to transactions using both the Transco and SPP systems. To implement this, they will agree to reciprocal waiver of access charges for transactions scheduled on one system that terminate on the other system. For transmission service on both the Transco's and SPP's systems to load outside the system (including transmission through and out service), the Transco and the SPP shall develop an appropriate single joint rate including a rate formula that compensates the Transco and the SPP for their proportionate

contribution to the transaction. The Transco tariff will reflect these arrangements, and SPP will file the necessary amendments to its tariff to reflect these arrangements as well. Within these limitations, the Transco shall possess the unilateral right to propose rates and rate structures (including innovative rate-making proposals) for transmission service under the Transco's transmission tariff.

6. *Unified OASIS Site*. The SPP and the Transco shall work to jointly develop and administer a unified OASIS site for transmission service under the SPP's and Transco's tariff. Both parties, however, shall have the option to build, maintain and administer additional features to the OASIS site in response to the needs of customers or the market. SPP and Transco shall ensure that market participants have the ability to obtain transmission service across the transmission facilities of the SPP/Transco RTO through the use of one OASIS site.

7. *Congestion Management*. The Transco shall develop and implement a congestion management plan for managing and relieving constraints within the Transco's system. The Transco and the SPP agree to work together in an effort to develop a single regional approach to congestion management. If the SPP so requests, Transco agrees to make its congestion management system available to SPP members at cost. Should SPP elect to develop its own system for congestion management, Transco and SPP will coordinate their systems to ensure maximum efficiency. At a minimum, they agree to develop a system for the joint procurement of ancillary services and a joint protocol to address the effect of parallel flow within the combined region that is caused by transactions scheduled on either SPP or Transco.

8. *Losses*. The Transco shall develop and implement a proposal for loss responsibility within the Transco's system. The Transco will coordinate with the SPP, and its members, to develop a proposal that avoids loss pancaking for losses on transactions over the SPP's and the Transco's system.

9. *Curtailments*. SPP shall act as the regional Security Coordinator for the SPP and Transco systems. In its role as Security Coordinator, SPP will allow Transco to provide redispatch alternatives to the Security Coordinator for transactions not scheduled by Transco that affect Transco flowgates that will alleviate the need for transmission line loading relief (TLR). These redispatch instructions will be by Transco.

10. *Operations*. The Transco shall be responsible for the operation of the Transco's transmission system. This includes the responsibility to establish ratings and operating procedures, develop transmission and generation outage schedules which will be coordinated with the SPP RTO, and to develop congestion management proposals. Transco and SPP will develop transmission and generation outage schedules designed to balance grid optimization with good utility practice.

11. *New Generator Interconnections*. Transco shall be responsible for evaluating and implementing requests for new generator interconnections on its system. SPP and Transco will work together to develop a single procedure for generator interconnections within the SPP/Transco RTO. Market participants seeking generator interconnections with Transco may use the SPP dispute resolution process.

12. *Reliability Oversight and Input*. The SPP shall be informed of, and shall be allowed to provide input into, the operational practices of the Transco so that the SPP can determine whether such practices have an adverse reliability impact anywhere in the region. The SPP may challenge operational procedures or practices of the Transco through the SPP's dispute resolution process; provided that the Transco's actions shall be binding pending the dispute resolution process.

13. *Planning and Expansion*. The Transco shall develop its own transmission plan for its region that includes both market-funded and rate-funded projects. This will be submitted to the SPP

for review and inclusion in an RTO-wide plan which the SPP shall prepare. Transco may, at its option, participate in the expansion of the transmission grid through market-funded projects. The SPP shall review all rate-funded projects for reliability considerations and the appropriateness of cost recovery through Transco rates. The SPP's review of market-funded projects shall be limited to reliability considerations. SPP and Transco will develop a formula to be used to apportion responsibility among all RTO transmission owners for the funding of projects that were not included in the Transco's plan but that the SPP has determined are required for regional reliability reasons.

SPP and Transco mutually agree to construct facilities to meet new requests for firm transmission service [subject to the development of appropriate cost-sharing arrangements.] In carrying out this obligation, Transco and SPP agree to use due diligence in meeting these requests regardless of whether the request originates on the Transco system or the portion of the grid under the control of the SPP transmission operator. SPP and Transco also agree to work together to determine the financial responsibility and the sharing of costs required to construct any new facilities required to meet these requests.

14. *Multi-State Transmission Planning Agreements*. SPP and Transco agree to work together jointly to support any multi-state transmission planning compact that is developed in their region.

15. *Billing*. The Transco shall be responsible for billing for transmission service that terminates on the Transco's system. The SPP shall be responsible for billing for transmission service that terminates on the SPP system. For transactions on both the SPP's and the Transco's systems that terminate outside the combined region, the billing shall be handled by the system on which the power exits the combined region, provided, however, that the rate for such service will be the single joint rate described in paragraph 4 of this document.

16. *Monitoring*. The SPP shall be responsible for monitoring all markets facilitated by Transco and/or SPP and its other members, including energy markets, ancillary services markets, and markets for transmission service and transmission rights. The monitoring function will also extend to SPP’s security coordination function. In its role as market monitor, the SPP shall have the authority to collect information and issue reports to appropriate regulatory agencies, but it shall not have the authority to impose penalties. The SPP's cost of monitoring the Transco's markets shall be borne by the Transco and its customers. The SPP and Transco shall be responsible for enforcing compliance with the provisions of their respective tariffs.

17. *Liability*. The Transco shall assume liability for all acts or omission resulting from the functions performed by the Transco and shall indemnify and hold the SPP harmless for its actions in performing those functions.

18. *Dispute Resolution*. The SPP, and its dispute resolution process, shall be responsible for resolving all disputes between the Transco and SPP concerning the arrangements set forth in this RTO Partnership Agreement. Disputes between the SPP and Transco shall be subject to non-binding arbitration unless the parties agree otherwise. Disputes between Transco, SPP members, or other market participants shall be subject to non-binding dispute resolution procedures unless the parties agree otherwise.

19. *Coordination*. The Transco and the SPP shall cooperate and use their best efforts to develop procedures and protocols to allow the Transco to operate within the structure of the SPP.

20. *Stakeholder and State Commission Input*. The SPP's oversight shall allow input from state commissions and market participants into the Transco's operations and procedures. This may take the form of an SPP advisory committee to be established for this purpose. The Transco shall

establish a liaison with such advisory committee, or comparable organization, and shall support the process allowing input from state commissions and market participants. Additionally, Transco will establish a Market Rules Committee, comprised of market participants, for the purpose of providing input and recommendations to Transco on changes to the market rules that will improve the overall efficiency and operation of the competitive generation market.

21. *Expandability of Transco*. The Transco shall be structured to reasonably accommodate other SPP members and non-members who elect to join. Any current SPP member shall have the right, upon one year's advance notice, (consistent with Section 4 of the SPP Members Agreement) to commit its assets to the Transco and to have its transmission facilities included within the Transco Tariff on terms and conditions comparable to the terms and conditions provided to the initial Transco members.

22. *Survivability*. This Agreement shall remain binding and shall be accommodated in the event that the SPP merges or combines with another regional transmission entity. In any instance where the provisions contained within this RTO Partnership Agreement, are in conflict with the SPP Bylaws or the SPP Membership Agreement, the terms and conditions of this document shall control.

23. *Withdrawal Rights*. The Transco shall have the same rights to withdraw from the SPP as other SPP members under section 4 of the SPP Membership Agreement. Such withdrawal shall be subject to FERC approval.

The Partnership Sub-Team proposes no modifications to SPP documents and that FERC accepted independent transmission companies be accommodated through individually proposed and approved attachments to SPP's membership agreement specifying any special provisions. Any such attachments would also require FERC acceptance.

Tariff (zones & expansion)

In its Order 2000, the FERC set out specific requirements regarding an RTO's responsibilities with respect to system planning and expansion. It specifically requires an RTO take ultimate responsibility for transmission planning and expansion within its region. In doing so, it must encourage market-motivated operation and investment actions necessary to relieve transmission congestion and accommodate state regulatory commission efforts to create multi-state agreements to review and approve new transmission facilities. The RTO must satisfy this requirement when it commences operation or file a plan, which includes specific milestones designed to ensure that the RTO will meet the requirement no later than three years after initial operation. This responsibility translates into the need to consider nontraditional mechanisms for the recovery of costs related to new transmission facilities.

In its initial RTO proposal SPP specified that, pursuant to the Membership Agreement, it will be responsible for regional planning in coordination with its members and that it retains the authority to direct the construction of new transmission facilities. Additionally, it stated that together with SPP's previously discussed market-based congestion management/pricing mechanism, such transmission planning and expansion responsibility enables SPP to administer efficient and reliable transmission service in coordination with state and regional authorities consistent with the RTO Final Rule. No revisions to the filed tariff were filed with the RTO application.

FERC issued its RTO NOPR on May 13, 1999. The SPP comprehensive tariff was still in development and was ultimately filed on September 7, 1999 and accepted by the FERC on December 17, 1999. SPP had developed its tariff cognizant of the NOPR requirements and believed that this tariff would be determined to be in compliance with the ultimate rule. Order 2000 was issued by the FERC on December 20, 1999. Based on its review of Order 2000, SPP did not see a need to re-file the Tariff as apart of its RTO filing.

FERC's order on SPP's filing found that SPP's tariff does not necessarily comply with its RTO requirements. It directed SPP to include in its subsequent RTO proposal a revised tariff or a detailed discussion of how the current tariff meets all of the RTO requirements of Order 2000. The SPP was also required to address how transmission expansion will be priced and how such pricing affects incentives for efficient expansion. With respect to its continued use of license plate rates, the Commission required that SPP explain the continued use of this rate system. Pursuant to this direction from the Commission, the Regional Transmission Organization Working Group (RTOWG) commissioned the RTWG to cover zones and expansion issues in preparation for the upcoming RTO filing.

I. RTO Issues - The following issues were raised in protests at the time of SPP's RTO filing or in subsequent collaboratives as RTO related transmission issues.

A. Transmission Planning and Expansion / Multi-state Agreements / Market Based Expansion of the Transmission System - Current planning requirements contained in the Tariff and their current implementation were reviewed. Attachment S to the Tariff currently allows for construction of transmission expansions and upgrades by others if the designated transmission owner cannot or will not construct the project in a timely manner. The construction of the project would be assigned based on the evaluation of proposals for project implementation. No changes to the Tariff provisions were suggested.

B. Costs Recovery/New Transmission Facilities - The current conclusion of the RTWG is that the method of cost recovery for new facilities does not need to be part of the initial RTO Tariff filing.

C. Rate Issues

i. Formula Rates - The RTWG has previously committed to assess the use of formula rates. A schedule for this assessment was concluded before the RTO discussions were reopened. The RTWG does not does not believe that schedule can be accelerated in consideration of the initial RTO Tariff filing. Concern was raised that the RTO effort was detracting from the ability to meet the established schedule.

ii. Levelized Rates, Performance Based Rates, Depreciation Rates for New Facilities - In Order 2000, FERC indicated a willingness to consider rate proposals including levelized rates, performance based rates, and accelerated depreciation rates for new facilities. The current conclusion of the RTWG is that the consideration of these mechanisms is not a necessary part of an initial RTO Tariff filing.

iii. Reassessment of License Plate Rates - The issue of the zonal rate design included in the current Tariff was discussed at length. The current zonal rate design was agreed upon as a method of getting through the transition period and of moving to retail open access. Moving immediately to a postage stamp rate for the entire SPP would result in significant cost shifting, creating winners and losers. The current discussion relating to this issue is that SPP should retain the current zonal rate design, while committing to a date certain for re-evaluation of the zonal rate design.

D. Market Based Congestion Management System, Real Time Balancing Market / Settlement of Imbalances, Development of an Ancillary Services Market - The Market Based Congestion Management System is within the scope of the Congestion Management Subteam. The Real Time Balancing Market / Settlement of Imbalances and Development of an Ancillary Services Market are currently within the scope of the Market Settlement Working Group and are significantly related to the design of the Congestion Management System. As these issues are concluded by the RTOWG, the Tariff will be revised as necessary (incrementally) to reflect such conclusions.

E. Transmission User Obligations (Attachment V in Comprehensive Tariff Filing) - The FERC rejected language in the September 7, 1999 Tariff filing that would have imposed certain tariff obligations on generators within the SPP even if they were not Tariff customers. This rejection was at least in part due to SPP's lack of ISO status at the time. The current conclusion of the RTWG is the inclusion of tariff obligations for generators is not a necessary part of an initial RTO Tariff filing.

F. Transition Issues

i. Bundled Load / Grandfathered Load. - All load under the same contract

ii. Transition Period

iii. Crediting issues - Transmission Customer Facilities.

It is the expressed desire of the marketers that all load, including native load and grandfathered contracts, be under the Tariff. This would allow one set of rules for all customers. While most participants have agreed in principal that placing all load under the tariff is an appropriate long-term goal, there are significant short term obstacles to achieving that goal. Currently several states have legislated retail rate freezes. This would require the owners of the transmission to bear the risk of any change to the rate. In states that do not currently have a rate moratorium, it is not possible to seek a rate change only on a single issue. Consequently, a company would be required to file a complete retail rate case, with its incumbent cost and risks, to reflect changes in its transmission costs in retail rates. The FERC has chosen not to abrogate existing grandfathered contracts. Absent the mutual agreement of the parties to these agreements, these contracts will remain in effect to their term.

The current Tariff has two sequential 5-year transition periods. The first period started with the approval of the Comprehensive Tariff (February 1, 2000). In the first period, there is no obligation to use the Tariff except for point-to-point service and service to wholesale loads where transmission has been unbundled or unbundling has been required by FERC. The Tariff may be used at the election of the transmission owner. During the second 5-year period all retail loads with the right to choose its power supplier must be served under the tariff. After the second transition period all native load is to be served under the tariff. These transition periods do not apply to grandfathered contracts, or the delivery of Federal hydropower within the SPA system. Grandfathered and Federal transmission contracts are assumed to continue to term.

While discussion will continue on this issue, lack of resolution will insure some protest of the tariff filing. Issues relating to inclusion of facilities of multiple transmission owners within a single zone (or rate credits crediting) are being discussed between AEP West, SPP and ETEC. The RTWG will continue to discuss this issue.

G. Seams Issues
   A. Rate Reciprocity with adjoining RTOs.
   B. Congestion Management with adjoining RTOs.
   C. One Stop Shopping across RTO boundaries.

These issues are within the scope of the RTOWG Seams Sub-team. The Tariff will be revised as necessary to reflect the conclusions of the RTOWG when finalized.

H. Scheduling deadlines for firm service - There was discussion of changing the Attachment P of the Tariff that contains the scheduling deadlines for firm schedules. The current requirement is that for a firm reservation holder to utilize the reservation a schedule must be in place by 10:00 A.M. the day prior to the actual schedule.

The current deadline was included in Attachment P to encourage the development of the non-firm energy market. The RTWG felt that frequent preemption of non-firm transmission by customers holding firm reservation would stifle the development of the non-firm market.

The objection raised was that the effect of the current rules is that, in current day operations, a firm reservation holder has no greater priority than a non-firm user even though a firm rate was being paid. There was some feeling that the firm reservation holder would put a schedule in place by the scheduling deadline and then request hourly changes just to ensure the ability to use the reservation if necessary.

I. Issues Arising after Scheduled Meetings - The ongoing evolution of FERC policy as stated in FERC orders continue to precipitate issues to be addressed. As an example, the following email from Mike Small indicates that the RTWG will need to have additional discussions regarding some of the planning and cost allocation aspects of the Tariff.

> From: Small, Mike
> Sent: Wednesday, July 05, 2000 11:06 AM
> To: Bourne, Pat
> Cc: Brown, Nick
> Subject: NEPOOL Order
>
> On June 28, 2000, FERC issued a lengthy order involving NEPOOL which contains discussions of some issues relevant to SPP's RTO development. ISO New England, 91 FERC 61,311. On planning, FERC directed the ISO to eliminate any decisional role transmission owners may have in the current plan. FERC wants the ISO alone to have the authority to develop the expansion plan. FERC also stated that all projects in the plan should be built following a competitive solicitation process including non-NEPOOL transmission owners.
>
> As to cost responsibility for upgrades (aside from interconnecting generators), FERC stated that "[o]ur general principle is to assign costs of various upgrades to those who benefit to the extent that they can be identified . . . ." FERC required the ISO to directly assign costs where there is agreement among the participants for such assignment and to develop objective, non-discriminatory guidelines to allocate costs where participants are unable to agree on the allocation of costs." FERC referred to PJM which among other things spreads the costs of all 500KV facility upgrades.
>
> On generation interconnection upgrades needed to maintain system reliability, FERC found that it was appropriate to allow direct assignment to the generator "of costs associated with direct interconnection and related upgrades."
>
> On congestion management, FERC accepted a nodal/zonal LMP approach as a "reasonable initial approach". FERC, however, expressed concerns that establishing different prices for generators and loads may create opportunities for gaming. Second, in calculating the weighting to be used in calculating the zonal prices, FERC directed that the weighting be based on actual hourly load at each node. Third, FERC wanted transmission customers to be able to submit bids indicating the highest price they are willing to pay for congestion.

II. Other Issues - There are other issues under consideration by the RTWG that are part of the ongoing evolution and development of the SPP Tariff and that have not been considered as RTO Issues or linked to SPP's filing for RTO status:

A. Interpretation of SPP Tariff, Section 2.2. - Right of first refusal

The decision of the FERC in docket ER00-46-000, upheld Entergy Power Marketing Inc.'s position that under the FERC's pro forma tariff and current SPP Tariff language a holder of a long-term reservation could wait as late as a date 60 days prior to the end of the reservation to exercise its right of first refusal to continue the contract.

The ability of a customer to maintain a right of first refusal until 60 days before the end of a reservation, prospectively requiring service indefinitely, raises concerns related to the effect of a customer reservation, of as little as one year duration, to drive speculative capacity expansion, impede the sale of other long term service or effectively lock up constrained interfaces. These issues are under active discussion and consideration is being given to any need to modify Tariff language.

B. SPP Tariff, Section 22.2. Modification of Firm Reservations - There has been a request to modify the Tariff to allow firm reservations to be modified for use of an alternative path on a firm basis for the remaining term of the reservation with consideration given for payment obligations incurred for the original reservation. If the modification could be accommodated the rate charged would be modified to that of the new path. After discussion, the motion as presented failed. Further discussion of alternative proposals is expected.

Public and Regulatory Education

FERC's order on SPP's initial RTO filing and the subsequent visit to FERC provided indication that particular emphasis needed to be placed on public information and pre-filing visits with FERC Staff and commissioners to provide education on SPP's collaborative process and its product. FERC's order stated "Moreover, we noted that all filings under Order No. 2000 would require a description of the efforts undertaken to permit public power entities and cooperatives to participate in the RTO. To date, SPP has not informed us of these efforts." Though the first two sections of SPP's initial filing provided detailed information on SPP's diverse membership and the open and inclusive development process, the message was not received. Therefore, the RTOWG agreed to place specific emphasis on public and regulatory education.

The RTOWG will host a public workshop on July 26 to provide information on SPP's RTO plan and seek final input from any and all interested parties. The RTOWG will meet on August 1 to consider input from the conference and determine if any modifications are necessary and prepare its final recommended documents for subsequent Board of Directors consideration.

Two visits are presently contemplated; one toward the end of filing development to inform the FERC of SPP's collaborative process and initial positions, and a second following Board of Directors approval of organizational documents as a pre-filing conference. Because of the potential for diverse positions on aspects of SPP's filing, participation in these visits be limited to the RTOWG co-chairs, staff and counsel with the specific intent to represent the consensus product only. This design is to mimic the transmission owner, transmission user and independent sectors of the Board of

Directors. Staff will notify the RTOWG of the dates and agendas for these FERC meetings.

Lastly, to ensure that SPP's filing considers the interest of all parties, after SPP Staff and counsel draft the FERC filing letter petitioning FERC recognition of SPP as an RTO, SPP membership and other parties that have participated in the collaborative process will be allowed at least one week to review and comment on the filing letter. The staff will then attempt to resolve any conflicts in resulting suggestions.

ORGANIZATIONAL DOCUMENTS

In fulfilling its charge, the RTOWG has developed proposed modifications to SPP's regional transmission service tariff and membership agreement that it believes are necessary for SPP to receive FERC recognition as an RTO pursuant to FERC Order 2000 and order on SPP's initial RTO filing. A form of a Section 203 filing is also provided for the benefit of jurisdictional transmission owners. No modification of SPP's bylaws is proposed. The modified membership agreement is attached indicating the proposed changes and a document from SPP's counsel is included which provides a brief explanation for each change.

RECOMMENDATION

The RTOWG recommends that the Board of Directors endorse this RTOWG report as indication that the organizational documents to be modified pursuant to RTOWG recommendations meet with the Board's satisfaction for a second SPP filing seeking FERC recognition as an RTO.

ATTORNEY-CLIENT/ATTORNEY
WORK PRODUCT PRIVILEGED AND CONFIDENTIAL
(Michael E. Small)

DESCRIPTION OF CHANGES TO
SPP MEMBERSHIP AGREEMENT(6-30-00)
AND POTENTIAL ISSUES

Part A of this memorandum describes the rationale for the major changes to the SPP Membership Agreement. As explained below, the changes principally involve adding language to show compliance with Order 2000 and reorganizing existing provisions. Part B describes a few issues of RTO compliance on which Order 2000 may not be clear or there are policy judgments that must be made.

A. Description Of Major Changes

1. Section 1.4 - The definition of “Distribution Facilities” was broadened to include other facilities which are not under the tariff to recognize that some customers, for example, may need transmission over a radial or a generator lead in addition to true distribution facilities and that they would pay a separate charge for the use of those facilities.

2. Section 1.5 - Changed the definition of “Effective Date” to state that this Agreement will be effective when the RTO is effective; i.e. accepted by FERC.

3. Section 1.12 - Added a definition of “Operational Control” as part of revisions to make clear that operational control will be transferred to SPP.

4. Section 1.13 - Added definition of “RTO Effectiveness” because some actions in the Agreement will be tied to that date including the basic effectiveness of the Agreement.

5. Section 1.15 - Included Board as part of definition of "SPP" as SPP acts pursuant to the direction of its Board. I am concerned about separating SPP Staff and Officers from the Board.

6. Section 1.21 - Added a definition of "Transmission Facilities" to detail the facilities subject to SPP's operational control.

7. Section 1.22 - Changed the definition of "Transmission Owner" largely to reflect the necessity of filing 203 applications by FERC regulated public utilities.

8. Section 2.1.1 - Added provisions which incorporate language and requirements from Order 2000 primarily on operational control. Moved most of the deleted sections to the transmission administration section and to the general section.

9. Section 2.1.2 a - Incorporated language from Order 2000 on Security Coordination.

10. Section 2.1.2 g - Incorporated language from Order 2000 on redispatch and also made clear that redispatch is not elective if necessary for the reliable operation of the Transmission Facilities.

11. Section 2.1.3 - Revised the transmission maintenance section to better conform to Order 2000 requirements by making clear that scheduled transmission maintenance outages must be changed if necessary to preserve reliability.

12. Section 2.1.4 f - Added language from Order 2000 on generation maintenance.

13. Section 2.1.5 - Added provisions incorporating language from Order 2000 on language.

14. Section 2.2.1 - In this section on transmission service, "General" included provisions from other sections which related to the provision of transmission.

15. Section 2.2.2 - Added language regarding transmission pricing to make clear that there would be no pancaking which is a FERC requirement. Also added a provision stating that SPP would re-evaluate zonal pricing in five years consistent with our discussions with the FERC Staff.

16. Section 2.2.4 - On ancillary services, added language to indicate compliance with Order 2000 requirements.

17. Section 2.2.6 - On ATC calculations, added language from Order 2000 on SPP testing and checking the data and having its position in place pending resolution of any dispute.

18. Section 2.2.7 - On congestion management, added language essentially stating that SPP will comply with FERC's requirements on congestion management.

19. Section 2.2.8 - On parallel path flows, included language stating that SPP's tariff administration addresses parallel path flows to show compliance with an Order 2000 requirement.

20. Section 2.2.9 - I was informed that there may be some facilities that are not transferred to SPP's operational control but which will be under the tariff. This provision recognizes this fact.

21. Section 2.3 - I revised this section to eliminate the agency relationship between SPP and the TO's and instead established a fiduciary relationship on a few items such as collecting and distributing revenues and discounting transmission. FERC had a concern about the agency relationship. A fiduciary relationship is more limited. I also added a provision which is found earlier in the agreement imposing a fiduciary obligation to make best efforts to design rates to allow full

cost of service recovery. Given the language in Order 2000 on RTO's having control over rate design, I thought that making this a fiduciary obligation may be important.

22. Section 2.4.3 - Governance Audit-Added a provision to satisfy FERC's requirement that the effectiveness of the governance structure be evaluated in two years.

23. Section 2.4.4 - Market Monitoring-Added a provision stating that SPP will cause implementation of the procedures necessary for compliance with Order 2000 market monitoring requirements.

24. Section 2.4.5 - General Filing Authority-Moved from another section to this general section.

25. Section 2.4.6 - Penalties and Incentives-Moved from another section to this general section.

26. Section 2.4.7 - General Authority-Moved from another section to this general section.

27. Section 3.0 - Revised to require the transfer of Operational Control to SPP.

28. Section 7.0 b - Termination of Agreement-Included language stating that prior obligations remain upon termination of the current agreement to prevent parties from escaping those obligations once the new Membership Agreement becomes effective.

29. Section 8.0 - Open Architecture-Added the language from FERC's regulations on Open Architecture.

B. Potential Issues

1. Filing Rights Of Transmission Owners

In Order No. 2000 and 2000-A, FERC stated that Transmission Owners control revenue requirements and may file to change their revenue requirements. See Order No. 2000-A, FERC Regs. Preambles ¶ 31,092 at 31,370 ("transmission owners may make Section 205 filings at any time to establish their requirement requirements and the just and reasonable payments they may charge the RTO for use of their facilities"). However, FERC provided the RTO with control over rate design. See Order No. 2000-A at 31,370 (RTO ultimately determines that rate design to file). Notwithstanding this statement, in Order No. 2000-A, FERC stated that:

> "We note that we stated in the Final Rule that we would entertain other approaches to the division of filing authority 'as long as they ensure the independent authority of the RTO to seek changes in rates, terms or conditions of transmission service and the ability of transmission owners to protect the level of the revenue needed to recover the costs of their facilities.'"

Order No. 2000-A at 31,371, quoting Order No. 2000 at 31,076.

The language in the Membership Agreement provides Transmission Owners with the clear ability to file to establish different rate designs for their zones. Section 3.10. It also provides SPP with the authority to file pricing charges. Section 2.2.2. As a result the Membership Agreement appears to satisfy Order No. 2000 on this point as SPP will have the right to file rate design changes. However, I cannot state with absolute certainty that FERC will accept the provision allowing Transmission Owners to change the rate design.

2. Transmission Maintenance

In Order No. 2000, FERC required that the RTO "must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards." Order No. 2000 at 31,104 (emphasis added). The Membership Agreement provides SPP with control over transmission maintenance outages "if forced transmission outages or other circumstances compromise the integrity or reliability of the Electric Transmission System." Section 2.1.3.c. SPP, however, does not have the right under the current draft to require a change in an outage schedule in other circumstances. The transmission owner coordinates such outages with SPP. The question is whether SPP's control over outages needs to go beyond reliability in order to comply with Order No. 2000. Again, I believe that the language complies with Order No. 2000; however, there is some uncertainty here.

3. Transfer Of Operational Control For Non-Jurisdictional Transmission Owners

The Membership Agreement contemplates that Transmission Owners that are not FERC-jurisdictional will not be transferring operational control through a § 203 filing at FERC. They instead will transfer operational control by executing the agreement. FERC Staff indicated that it may require that SPP ask for § 203 authority to assume operational control from these entities. FERC Staff, however, indicated that this issue can be finessed through the filing. I do not propose any changes to the language of the Membership Agreement to address this point. We will need to decide whether to have SPP request the authority under § 203 to assume operational control. To my knowledge, this is an issue which FERC has yet to address.

4. SPP's Fiduciary Responsibilities To the Transmission Owners

In Section 2.3, I have revised the current Membership Agreement to change SPP's relationship from an agency to a fiduciary relationship on four specified matters. I expect that this change will be accepted by FERC as the FERC approved Midwest ISO Agreement contains a similar provision. However, I cannot state this conclusively here as FERC has yet to address this issue in an RTO context.

5. Transmission Construction

Section 3.3 of the draft assumes that the Transmission Owners will construct the new facilities. In a recent NEPOOL order, FERC stated that "all projects in the Plan should be built following a competitive solicitation." ISO New England, Inc., 91 FERC ¶ 61,311 (June 28, 2000). Also, in the planning and expansion section of Order No. 2000, FERC stated that an RTO must "encourage market-motivated operating and investment actions for preventing and relieving congestion." Order No. 2000 at 31,163. Therefore, there is some uncertainty on the acceptability of this provision.

SPP/tariff/description of changes to SPP membership agreement

DRAFT 6/30/00

SOUTHWEST POWER POOL

RTO MEMBERSHIP AGREEMENT

2000~~July 1999~~

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Southwest Power Pool

RTO Membership Agreement

This Agreement is made between and among the Members and SPP, as defined herein.

1.0 Definitions

1.1 Agreement

This RTO Membership Agreement.

1.2 Board of Directors

The Board of Directors elected consistent with SPP's Bylaws.

1.3 Bylaws

SPP's Bylaws or any successor document.

1.4 Distribution Facilities

Facilities which are not offered for service under the Transmission Tariff and which would be the ~~the~~ subject of a ~~separate distribution~~ charge separate from the Transmission Tariff charges~~pursuant to the Transmission Tariff~~.

1.5 Effective Date

For each Member, this Agreement is effective on the date of RTO Effectiveness ~~January 1, 2000~~ or upon the date of execution by that Member if after such date~~January 1, 2000~~.

1.6 Electric Transmission System

The transmission facilities subject to SPP's tariff administration except for any Distribution Facilities.

1.7 FERC

The Federal Energy Regulatory Commission.

1.8 Good Utility Practice

Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act, to the exclusion of all others, but rather to be a range of acceptable practices, methods, or acts generally accepted in the region. SPP Criteria and NERC Policies and Standards are considered Good Utility Practice.

1.9 Members

Signatories to this Agreement that have completed the application requirements pursuant to the Bylaws.

1.10 NERC

North American Electric Reliability Council or successor organizations.

1.11 Non-Transmission Owner

Those signatories which are not Transmission Owners under this Agreement.

1.12 Operational Control

The authority provided to SPP pursuant to Section 2 of this Agreement.

1.13 RTO Effectiveness

The date the SPP Regional Transmission Organization (RTO) as that term is used in FERC Order Nos. 2000 and 2000-A becomes effective. The RTO shall become effective on the date FERC finds that SPP satisfies such RTO requirements.

1.14~~2~~ Security Coordinator

SPP in performing its security coordinator function as recognized by NERC pursuant to its policies, pursuant to SPP Criteria and pursuant to this Agreement.

1.15~~3~~ SPP

Southwest Power Pool, Inc., its officers, employees,~~, and~~ agents and Board of Directors. ~~This definition does not include the Board of Directors.~~

1.16~~4~~ SPP Criteria

SPP's approved operating and planning criteria.

1.17~~5~~ SPP Region

The geographic area encompassing the transmission systems of SPP Transmission Owners.

1.18~~6~~ Standards of Conduct

SPP's Standards of Conduct which apply to conduct of independent board directors, officers, employees, and consultants.

1.19~~7~~ Tariff Facilities

The T~~t~~ransmission F~~f~~acilities and Distribution Facilities subject to SPP's tariff administration.

1.20~~18~~ Transmission Customer

A customer under the Transmission Tariff.

1.21 Transmission Facilities

The facilities subject to SPP's Operational Control. These facilities consist of transmission facilities that are 60 KV and above and transformers with two primary windings of 60KV and above. SPP may direct the transfer of other facilities to its Operational Control subject to all necessary regulatory approvals being received.

1.22~~19~~ Transmission Owner

A signatory to this Agreement which transfers Operational Control to SPP through filings under Section 203 of the Federal Power Act together with this Agreement or simply by executing this Agreement or appoints ~~appoints~~ SPP as its agent to provide service under the Transmission

Tariff over Tariff Facilities which it owns or controls which are not Transmission Facilities subject to SPP's Operational Control. All Transmission Owners that are public utilities under Section 201 of the Federal Power Act shall submit or effect the submission of applications under Section 203 of the Federal Power Act to transfer Operational Control to SPP of all of their Transmission Facilities.

1.23~~0~~ Transmission Tariff

The nondiscriminatory, open-access transmission service tariff on file with the FERC pursuant to Section 205 of the Federal Power Act under which SPP ~~will~~ offers transmission service, or any such nondiscriminatory successor tariff.

2.0 Rights, Powers And Obligations Of Southwest Power Pool

SPP possesses the rights, powers, and obligations as detailed in this Section 2 and shall exercise Operational Control as defined herein..

2.1 Operation, Reliability, Maintenance and Planning

2.1.1 General

a. SPP shall control the operation of the Transmission Facilities either directly or through the issuance of directives to the Transmission Owners. SPP's control includes directing the switching of transmission elements into and out of operation in the transmission system, monitoring and controlling real and reactive power flows, monitoring and controlling voltage levels, and scheduling and directing the operation of reactive resources.

b. With regard to operational functions that are shared by SPP and Transmission Owners, SPP shall ensure that this sharing of operational functions shall not adversely affect reliability or provide any Market Participant with an unfair competitive advantage.

c. SPP shall exercise Operational Control and its Security Coordination functions in a non-discriminatory manner for all Market Participants.

d. SPP shall possess the authority for or to direct the receiving, confirming, and implementing of all interchange schedules.

e. Within two years after the RTO Effectiveness, SPP shall propare a public report assessing the efficacy of its operational arrangements including whether any division of Operational

Control hinders it in providing reliable, non-discriminatory and efficiently priced transmission service.

~~**a.** SPP is authorized by the Transmission Owners pursuant to this Agreement to schedule transactions and to administer transmission service over Tariff Facilities as an agent of the Transmission Owners as necessary to provide service in accordance with the SPP Transmission Tariff. SPP shall not operate or direct the operation of the Tariff Facilities except in its role as Security Coordinator.~~

f~~b~~. SPP shall function in accordance with Good Utility Practice and shall conform to applicable reliability criteria, policies, standards, rules, regulations, guidelines and other requirements of SPP and NERC, each Transmission Owner's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements specified in this paragraph), and all applicable requirements of federal and state regulatory authorities. SPP shall notify FERC immediately if implementation of these criteria, etc. prevent it from providing reliable, non-discriminatory transmission service.

g~~c~~. SPP shall maintain a publicly available registry of all facilities that constitute the Electric Transmission System.

~~**d.** SPP shall review and approve, as appropriate, requests for service and schedule transmission transactions and shall determine available transfer capability under the Transmission Tariff; provided that SPP shall coordinate with affected Transmission Owners when processing requests for service involving such Transmission Owners' Tariff Facilities.~~

h~~e~~. SPP shall be responsible for coordinating with neighboring regional organizations as appropriate. SPP shall submit filings with FERC to allow implementation of procedures to address parallel path flow issues with other regions to be effective within three years after RTO Effectiveness.

~~**f.** SPP shall not exercise its administration of transmission service over the Tariff Facilities in such a way as to interfere with rights of Transmission Owners or Transmission Customers in contracts between a Transmission Owner and a Transmission Customer that are in effect as of the Effective Date of this Agreement except as permitted by the Transmission Tariff.~~

~~**g.** SPP shall be responsible for documenting all transmission service requests, the disposition of such requests, and any supporting data required to support the decision with respect to such~~

~~requests. SPP shall negotiate as appropriate to develop reciprocal service, equitable tariff application, compensation principles, and any related arrangements.~~

~~**h.** SPP shall propose and file modifications with FERC to the Transmission Tariff and to make any other necessary filings subject to necessary Board of Directors approval for those filings that the Board requires be brought to it for its approval pursuant to the provisions of Section 2.2.1 and subject to reserved Transmission Owner rights pursuant to Section 3.10.~~

~~**i.** SPP shall develop penalties and incentives, subject to FERC filings where appropriate.~~

i~~j~~. SPP shall direct Transmission Owners pursuant to the provisions of Section 3.3 to construct transmission facilities in accordance with coordinated planning criteria or if necessary under the Transmission Tariff.

~~**k.** SPP shall take any actions necessary for it to carry out its duties and responsibilities subject to receiving any necessary regulatory approvals and any necessary approvals by the Board of Directors.~~

2.1.2 Reliability

SPP shall have responsibility for reliability of the Electric Transmission System in connection with its rights, powers, and obligations under this Agreement. SPP shall act as the Security Coordinator of the Electric Transmission System, and as such, shall have security monitoring and emergency response responsibilities pursuant to related SPP Criteria and the following requirements:

a. As Security Coordinator, SPP shall (i) perform load flow and stability studies to anticipate, identify and address security problems, (ii) exchange security information with local and regional entities; and (iii) monitor real-time operating characteristics such as the availability of reserves, actual power flows, interchange schedules, system frequency and generation adequacy.

b~~a~~. SPP shall monitor real-time data to determine whether any control areas are experiencing generation capacity deficiencies. If a generation capacity deficiency event threatens the security of the Electric Transmission System, SPP shall be authorized to and shall direct the acquisition of generation capacity and, if that direction is not satisfied, the shedding of firm load in the deficient control area.

c~~b~~. SPP shall work with other security coordinators to develop regional security plans and emergency operating procedures.

d~~c~~. SPP shall maintain emergency response procedures for responding to specified critical contingencies and shall continuously analyze issues that may require the initiation of such actions.

e~~d~~. SPP is authorized to and shall direct the response to any emergency and Members shall carry out the required emergency actions as directed by SPP (except in cases involving endangerment to the safety of employees or the public), including the shedding of firm load if required for regional security.

f~~e~~. After the conclusion of an emergency condition, any affected entity that disagrees with SPP's handling of the emergency may resolve that disagreement pursuant to SPP's dispute resolution procedures.

g~~f~~. SPP shall monitor and coordinate the maintenance of adequate Electric Transmission System voltage levels with control areas and Transmission Owners, where appropriate.

h~~g~~. SPP shall direct redispatch of generation if necessary for the reliable operation of the Transmission Facilities. SPP shall pay the generator for the redispatch ~~in accordance with the Transmission Tariff subject to the generator receiving appropriate compensation~~ pursuant to an applicable rate schedule. SPP shall be allowed to recover these costs through a FERC approved rate schedule.

2.1.3 Transmission Maintenance

Coordination with SPP is required for all planned maintenance Tariff or Transmission of ~~Tariff~~ Facilities consistent with the following requirements:

a. SPP shall review planned transmission maintenance schedules for Tariff Facilities submitted by Transmission Owners for a minimum of a rolling one-year period. These planned maintenance schedules shall be updated daily. Planned transmission maintenance requests shall be submitted to SPP at least one week in advance of an outage.

b. SPP shall analyze such planned transmission maintenance requests to determine their effect on available transfer capability, ancillary services, the security of the Electric Transmission System, and any other relevant effects. Within two business days of receiving a planned maintenance request, SPP shall provide a response. If SPP's response indicates that such planned transmission maintenance will have an adverse impact, Transmission Owners shall work with SPP to minimize the impact of such planned maintenance.

c. SPP shall notify Transmission Owners of the need ~~of the need~~ to change previously-reviewed planned transmission maintenance outages for Transmission Facilities if forced transmission outages or other circumstances compromise the integrity or reliability of the Electric Transmission System. ~~If the Transmission Owners are fully compensated for any additional costs resulting from any changes in maintenance schedules as provided in an applicable rate schedule, t~~The Transmission Owners shall revise maintenance outages to address such ~~emergency~~ circumstances.

d. As part of its review process, SPP shall identify planned transmission maintenance schedules that limit available transfer capability. If requested by a Transmission Customer, SPP shall identify opportunities and associated costs for rescheduling planned maintenance to enhance available transfer capability. Transmission Owners shall be compensated for the additional costs of rescheduled maintenance as provided in an applicable rate schedule.

e. SPP shall be responsible for documenting all planned transmission maintenance requests, the disposition of those requests, and all data supporting the disposition of each request and shall update and publish maintenance schedules as needed.

f. SPP shall coordinate with Transmission Owners to the extent practicable to implement schedules for unplanned transmission maintenance when conditions endanger the safety of employees or the public, may result in damage to facilities, or may result in the unsatisfactory operation of the Transmission Owner's transmission system or any other transmission system.

g. SPP shall maintain as part of its Transmission Tariff a provision providing for compensation to Transmission Owners for changes to planned maintenance schedules.

2.1.4 Generation Maintenance

SPP shall coordinate the maintenance of generating units as appropriate to the extent such generation maintenance directly affects the capacity or reliability of the Electric Transmission System and the generation is located in the SPP Region as follows:

a. SPP shall review planned generating unit maintenance schedules submitted by generators or generation owners for a minimum of a rolling one-year period. The planned maintenance schedules shall be updated daily. SPP shall keep such information confidential.

b. SPP shall analyze a planned generating unit maintenance schedule to determine its effect on available transfer capability, ancillary services, the security of the Electric Transmission System, and any other relevant effects. SPP shall inform a generator or generation owner if its maintenance schedule is expected to have an impact on the security of the Electric Transmission System.

c. As part of its review process, SPP shall identify generating unit maintenance schedules that limit available transfer capability and shall identify opportunities and associated costs for rescheduling planned maintenance to enhance available transfer capability.

d. The owner of any generator that changes planned maintenance as a result of SPP review or coordination pursuant to this Section 2.1.4 shall be compensated fully for additional costs associated with rescheduling such planned generation maintenance in accordance with an applicable rate schedule.

e. SPP shall be responsible for documenting all planned generating unit maintenance schedules, all schedule changes, and all SPP studies and services performed with respect to planned generation maintenance.

f. SPP shall not share information as to the generators' maintenance schedules with any other market participants or affiliates of market participants.

2.1.5 Planning Activities

a. SPP shall engage in such planning activities, in coordination with affected Transmission Owners and other Members, as are necessary to fulfill its obligations under this Agreement, SPP Criteria and the Transmission Tariff. Such planning shall conform to applicable reliability requirements of SPP, the North American Electric Reliability Council, or any successor organizations, each Transmission Owner's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements), and all applicable requirements of federal or state regulatory authorities. Such planning shall seek to minimize costs, consistent with the reliability and other requirements set forth in this Agreement. The division of responsibility for planning between Non-Transmission Owners, Transmission Owners, and SPP is set forth in SPP Criteria.

b. As part of its planning activities, SPP shall be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and to coordinate such efforts with the appropriate state authorities.

c. SPP shall develop and implement no later than three years after RTO Effectiveness a planning and expansion process that encourages market-driven operating and investment actions.

d. SPP also shall encourage and accommodate efforts by state commissions to create multi-state agreements to review and approve new transmission facilities.

2.2 Non-Discriminatory Transmission Service

SPP shall offer and administer transmission service over Tariff Facilities as specified in the Transmission Tariff.

2.2.1 General

a. SPP is authorized by the Transmission Owners pursuant to this Agreement to schedule transactions and to administer transmission service over Tariff Facilities as necessary to provide service in accordance with the SPP Transmission Tariff.

b. SPP shall review and possess the sole authority to approve or deny, as appropriate, requests for service including interconnection requests and schedule transmission transactions and shall independently determine available transfer capability under the Transmission Tariff; provided that SPP shall coordinate with affected Transmission Owners when processing requests for service involving such Transmission Owners' Tariff Facilities.

c. SPP shall not exercise its administration of transmission service over the Tariff Facilities in such a way as to interfere with rights of Transmission Owners or Transmission Customers in contracts between a Transmission Owner and a Transmission Customer that are in effect as of the Effective Date of this Agreement except as permitted by the Transmission Tariff.

d. SPP shall be responsible for documenting all transmission service requests, the disposition of such requests, and any supporting data required to support the decision with respect to such requests. SPP shall negotiate as appropriate to develop reciprocal service, equitable tariff application, compensation principles, and any related arrangements.

2.2.2~~1~~ Pricing

a. In connection with its administration of the Transmission Tariff, SPP on behalf of its Members may propose to the FERC such transmission pricing for transmission service as is necessary to fulfill its obligations under this Agreement, and may propose to the FERC such changes in prices, pricing methods, terms, and conditions as are necessary to continue to fulfill such obligations. Board of Directors approval of such filings is required for any matters that the Board deems as appropriate for its consideration and approval. The Transmission Tariff rates shall be designed and administered so as to recover full cost of service to the greatest extent practicable associated with the provision of transmission service under the Transmission Tariff for Tariff Facilities. In addition, Transmission Customers under SPP's Transmission Tariff shall not be charged multiple base transmission charges for any single transactions for the recovery of capital costs for transmission service over the Tariff Facilities. Notwithstanding the foregoing, each Transmission Owner possesses the right to revise certain rates as provided in Section 3.10 of this Agreement.

b. No later than five years after RTO Effectiveness, SPP shall file with FERC a report justifying continuation of the zonal pricing structure or a new pricing structure.

2.2.3~~2~~ Standards of Conduct

SPP, its independent directors, officers, employees, contractors, and agents shall adhere to the SPP Standards of Conduct.

2.2.4~~3~~ OASIS

SPP shall administer an Open Access Same-time Information System (OASIS) or successor systems for administration of transmission service. The OASIS, or any successor system, shall conform to the requirements for such systems as specified by the FERC.

2.2.54 Ancillary Services

SPP shall be the supplier of last resort for the ancillary services required by the FERC. SPP shall have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services will be provided. SPP also shall maintain provisions in its Transmission Tariff allowing transmission customers access to a real-time balancing market. ~~SPP, as part of the Transmission Tariff, shall facilitate the provision of such ancillary services as are required to be offered by the FERC.~~

2.2.6~~5~~ Transmission Service Scheduling

a. SPP shall schedule and curtail transmission service in accordance with the Transmission Tariff.

b. SPP shall, in consultation with Members, develop and from time-to-time amend when necessary, detailed scheduling protocols and procedures for service under the Transmission Tariff, which shall be provided to all Members and be made publicly available.

c. To the extent SPP relies on available transfer capability data supplied by Transmission Owners, SPP shall test and check the data. In the event of a dispute between SPP and the Transmission Owner, SPP's position shall be maintained pending resolution of the dispute.

2.2.7 Congestion Management

Beginning no later than one year after RTO Effectiveness, SPP shall maintain in its Transmission Tariff a market mechanism to manage transmission congestion over the Transmission Facilities. If such market mechanism is not in place upon RTO Effectiveness and until such time as it is in effect, SPP shall maintain in its Transmission Tariff an effective protocol for managing congestion.

2.2.8 Parallel Path Flows

SPP's administration of the Transmission Tariff shall address parallel path flows within SPP through [among other things] its flow-based reservation and scheduling system.

2.2.9 Facilities Not Under SPP's Operational Control

By agreement of SPP and a Transmission Owner, the Transmission Owner's facilities that are not Transmission Facilities under this Agreement may be included under the Transmission Tariff. SPP shall have the right to exercise authority over those facilities necessary for it to administer transmission service and which meaningful impact transfer capability.

2.3 Responsibilities of Southwest Power Pool to Transmission Owners

SPP shall have the following fiduciary responsibilities to ~~administer transmission service and receive and distribute revenues to~~ Transmission Owners under this Agreement: ~~as their agent in accordance with the Transmission Tariff and this Agreement. Notwithstanding the foregoing, SPP shall act pursuant to the direction of the Board of Directors except that neither the Board of Directors nor SPP may take any action which interferes with the following obligations:~~

a. Using ~~In performing their obligations under this Agreement, SPP, and the Board of Directors shall use their individual and collective~~ best efforts to avoid damage to the Tariff Facilities or any property of the Transmission Owners or Non-Transmission Owners affected by SPP activities.

b. ~~SPP shall~~ Collecting and distributinge~~e~~ revenues to the Transmission Owners in accordance with the Transmission Tariff.

c. Using ~~In discounting transmission services in accordance with the Transmission Tariff, it shall be the duty of SPP to use~~ best efforts to maximize transmission service revenues associated with such transmission services in discounting transmission services in accordance with the Transmission Tariff.

d. Using best efforts to promote the design and development of Transmission Tariff rates to allow recovery of full cost of service to the greatest extent practicable and subject to receiving necessary regulatory approvals.

2.4 Additional Obligations and Rights of SPP

2.4.1 Inspection and Auditing Procedures

SPP shall grant each Member, their employees, agents, or external auditors, and federal and state regulatory authorities having jurisdiction over SPP or any Member, such access to SPP's books and records as is necessary to verify compliance by SPP with this Agreement and to audit and verify transactions under this Agreement. Such access shall be at reasonable times and under reasonable conditions. SPP shall also comply with the reporting requirements of federal and state regulatory authorities having jurisdiction over SPP with respect to the business aspects of its operations. Contacts between officers, employees, and agents of any Member and those of SPP shall comply with the Standards of Conduct.

2.4.2 Stranded Cost Recovery Charges

SPP shall collect and distribute, as appropriate, any stranded cost recovery charges pursuant to applicable schedules accepted by appropriate regulatory entities.

2.4.3 Governance Audit

Within thirty days before the two year anniversary of RTO Effectiveness, SPP shall submit an audit of the independence of its governance process.

2.4.4 Market Monitoring

SPP shall implement or effect the implementation of market monitoring in accordance with Order Nos. 2000 and 2000-A and any other applicable FERC orders.

2.4.5 General Filing Authority

SPP shall propose and file modifications with FERC to the Transmission Tariff and make any other necessary filings subject to necessary Board of Directors approval for those filings that the Board requires be brought to it for its approval pursuant to the provisions of Section 2.2.2 and subject to reserved Transmission Owner rights pursuant to Section 3.10.

2.4.6 Penalties and Incentives

SPP shall develop penalties and incentives, subject to FERC filings where appropriate.

2.4.7 General Authority

SPP shall take any actions necessary for it to carry out its duties and responsibilities subject to receiving any necessary regulatory approvals and any necessary approvals by the Board of Directors.

3.0 Commitments, Rights, Powers, And Obligations Of Transmission Owners and Non-Transmission Owners

Transmission Owners and Non-Transmission Owners have made the following commitments, and shall have the following rights and shall be responsible for the following functions some of which apply only to Transmission Owners, some only to Non-Transmission Owners, and some to both. In order to be considered as a Transmission Owner under this Agreement, each

Member intendinged to be a Transmission Owner shall identify itself as a Transmission Owner when executing this Agreement. A non-Transmission Owner under this Agreement owning or controlling Tariff Facilities may have its status changed to a Transmission Owner under this Agreement upon notice to SPP and execution of this Agreement as a Transmission Owner.

a. Each Transmission Owner shall transfer Operational Control of its Transmission Facilities, subject to receiving all necessary regulatory authorizations, thereby allowing ~~authorizes~~ SPP to (i) direct the operation of the Transmission Facilities in accordance with the terms of this Agreement and (ii) to administer ~~act as its agent~~ (ii) ~~in providing~~ transmission service under the Transmission Tariff over that Transmission Owner's Tariff Facilities. ~~; and (ii) in receiving funds from Transmission Customers relating to transmission service over Tariff Facilities and in distributing funds to it.~~

b. Transmission Owners and Non-Transmission Owners, if they own generators within the SPP Region which directly affect the capacity or reliability of the Electric Transmission System, shall offer to provide the ancillary services required under the Transmission Tariff at rates approved by regulatory authorities, where appropriate to the extent such generators are able to provide such ancillary services.

c. Transmission Owners shall operate and maintain their Tariff Facilities subject to the requirements of this Agreement.

d. Transmission Owners that are control area operators shall continue to operate their control areas for local generation control and economic dispatch, and shall be responsible for identifying and addressing local problems in a secure and reliable manner.

e. Transmission Owners shall provide transmission service over their Tariff Facilities at the direction of SPP pursuant to the terms of the Transmission Tariff.

f. Members agree to comply with instructions of SPP in its role as Security Coordinator.

g. Transmission Owners shall retain all rights of ownership including legal and equitable title in their Tariff Facilities, subject to the provisions of this Agreement. Nothing in this Agreement shall be deemed to restrict or prohibit access to their Tariff Facilities by the Transmission Owners, or those acting under their authority, consistent with the provisions of this Agreement.

h. Notwithstanding any other provision in this Agreement, no Transmission Owner shall be obligated or be considered as allowing transmission over its facilities if such transmission would cause the loss of the tax exempt status of any Transmission Owner or any bonds or other debt of a Transmission Owner.

3.1 Redispatch, and Curtailment

Each Member which owns or controls generation shall follow the directions of SPP in its role as Security Coordinator, in redispatching generation if such generation directly affects the reliability and capability of the Electric Transmission System and if it is located within the SPP Region. Each Member also shall follow the directions of SPP to effectuate curtailment of load, if so directed by SPP, its role as Security Coordinator or as administrator of the Transmission Tariff. Members shall submit and coordinate with SPP unit schedules and must-run units within the SPP Region that affect Electric Transmission System capability or reliability. Members providing such redispatch shall receive appropriate compensation in accordance with appropriate rate schedules and market conditions, if applicable.

3.2 Transmission and Generation Maintenance Practices

Each Transmission Owner shall maintain its Tariff Facilities in accordance with Good Utility Practice. Each Member shall maintain its generation facilities subject to this Agreement in accordance with Good Utility Practice. Transmission Owners shall coordinate maintenance on their Tariff Facilities in accordance with Section 2.1.3 of this Agreement. Members owning or controlling generation facilities within the SPP Region directly affecting Electric Transmission System capability or reliability shall coordinate maintenance of such facilities with SPP in accordance with Section 2.1.4 of this Agreement.

3.3 Construction

a. Each Transmission Owner shall use due diligence to construct transmission facilities as directed by SPP in accordance with the Transmission Tariff, subject to such siting, permitting, and environmental constraints as may be imposed by state, local and federal laws and regulations, and subject to the receipt of any necessary federal or state regulatory approvals. Such construction shall be performed in accordance with Good Utility Practice, applicable SPP Criteria, industry standards, each Transmission Owner’s specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements), and in accordance with all applicable requirements of federal or state regulatory authorities. Each Transmission Owner shall be fully compensated to the greatest extent permitted by FERC, or other regulatory authority for the costs of construction undertaken by such Transmission Owner in accordance with the Transmission Tariff.

b. After a new transmission project has been approved, SPP will direct the appropriate Transmission Owners to begin implementation of the project. If the project forms a connection between facilities of a single Transmission Owner, that Transmission Owner will be designated to provide the new facilities. If the project forms a connection between facilities owned by two different Transmission Owners or between a new facility and the facilities of a Transmission Owner, both entities will be designated to provide the new facilities. The two entities will agree between themselves how much of the project will be provided by each entity. If agreement cannot be reached, SPP will facilitate the ownership determination process.

c. A designated provider for a project can elect to arrange for a new entity or another existing Transmission Owner to build and/or own the project in their place. If a designated provider or providers do not or cannot agree to implement the project in a timely manner, SPP will solicit and evaluate proposals for the project from other entities and select a replacement designated provider.

3.4 Use of Distribution Facilities

Each Transmission Owner shall provide such service over its Distribution Facilities, where applicable, as is necessary to effectuate transmission transactions administered by SPP, at approved rates, and subject to a separate tariff or agreement as appropriate.

3.5 Providing Information

Each Member shall provide such information to SPP as is necessary for SPP to perform its obligations under this Agreement and the Transmission Tariff and for planning and operational purposes. Such information may be treated as confidential when so designated by the providing member so long as its designation is reasonable.

3.6 Facilities Access

Each Transmission Owner shall allow SPP, such access to Tariff Facilities as is necessary for SPP to perform its obligations under this Agreement. Such access shall be at reasonable times and under reasonable conditions.

3.7 Inspection and Auditing Procedures

Each Transmission Owner shall grant SPP and each regulatory authority having jurisdiction over that Transmission Owner, such access to the Transmission Owner's books and records as is necessary for SPP to perform its obligations under this Agreement and to audit and verify transactions under this Agreement. Such access shall be at reasonable times and under reasonable conditions. A Transmission Owner shall not be required to provide access to confidential information unless it consents, its consent not to be unreasonably withheld. Such Transmission Owner may require reasonable disclosure conditions before giving its consent. Disclosure of confidential information shall be made consistent with such disclosure conditions or in accordance with any effective order requiring production of such confidential information issued by a court or regulatory authority. SPP shall provide the affected Transmission Owner immediate notice of any request by an entity to review any such confidential information.

3.8 Compliance with Bylaws and Other Policies and Procedures

a. Each Member agrees to and will comply with and abide by the provisions of the SPP Bylaws.

b. Each Member shall comply with all approved and applicable SPP and NERC policies, principles, criteria, standards, and guides and monitoring and certification procedures.

c. Members who are also members of another NERC regional reliability council may, at their request and upon approval of the President, be granted a waiver of responsibilities associated with SPP Criteria and/or Bylaws that are duplicative of or inconsistent with responsibilities of membership in another council. Members receiving such a waiver agree to forgo voting privileges on issues before any organizational group pertaining to waived responsibilities.

3.9 Planning and Participation

Each Member shall be entitled to participate and each Transmission Owner shall participate in regional joint planning and coordinated operation of the Electric Transmission System.

3.10 Pricing

Each Transmission Owner shall possess the unilateral right to file with FERC to change the rates or rate structure for transmission service over its Tariff Facilities and to submit proposals or filings governing new construction with FERC; provided, however, a Transmission Owner may not submit a proposal which results in a Transmission Customer paying two or more transmission charges for transmission for one transaction under the Transmission Tariff involving Tariff Facilities (excluding Distribution Facilities for which an additional charge may be imposed and Grandfathered Agreements as defined in the Transmission Tariff). No SPP approval is required for such filings though the Transmission Owner shall notify SPP in advance of the filing of its intention to submit a filing with FERC and provide SPP with a copy of the filing.

4.0 Withdrawal Of Transmission Owners' Facilities And Withdrawal By Non-Transmission Owners

4.1 Withdrawal Notice

4.1.1 Transmission Owners

A Transmission Owner may, upon submission of a written notice of withdrawal to the President, commence a process of withdrawal of its Tariff Facilities from SPP's administration. Such withdrawal shall not be effective until October 31 of the calendar year following the calendar year in which notice is given; provided that the Transmission Owner must provide at least 12 months notice. With regard to any such withdrawal by a FERC public utility, the withdrawing Transmission Owner's withdrawal shall not become effective until FERC has accepted the notice of withdrawal or otherwise allowed such withdrawal. At the time the withdrawal becomes effective and unless otherwise requested by the withdrawing Transmission Owner, it shall be classified as a Non-Transmission Owner under this Agreement. If such withdrawal of facilities creates a situation in which a second Transmission Owner is no longer physically interconnected with the Electric Transmission System, SPP shall determine if such withdrawal affects the ability of such second Transmission Owner to continue its membership as a Transmission Owner.

4.1.2 Non-Transmission Owners

Non-Transmission Owners may withdraw upon providing written notice to the President. Such withdrawal shall not be effective until October 31 of the calendar year following the calendar year in which notice is given. Non-Transmission Owners withdrawing shall pay all Existing Obligations as defined in Section 4.2.2.

4.2 Effect of Withdrawal on Contractual Obligations

This Section 4.2 applies to withdrawals under both Sections 4.0 and 5.0 of this Agreement as well as any termination pursuant to Section 6.0.

4.2.1 Users Held Harmless

Transmission Customers taking service which involves facilities being withdrawn by a Transmission Owner from SPP's administration and which involves transmission contracts executed before the Transmission Owner provided notice of its facilities withdrawal shall continue to receive the same service for the remaining term of the contract at the same rates, terms, and conditions that would have been applicable if there were no withdrawal of facilities. The withdrawing Transmission Owner shall agree to continue providing service to such Transmission Customers, and shall receive revenues calculated in accordance with the Transmission Tariff but no more in revenues for that service than if there had been no withdrawal of facilities by such Transmission Owner.

4.2.2 Existing Obligations

All financial obligations incurred and payments applicable to time periods prior to the effective date of such withdrawal shall be honored by SPP and the withdrawing Member. The withdrawing Member's existing obligations shall include, as calculated pursuant to the SPP Bylaws, all costs or expenses incurred up until the date withdrawal becomes effective. The withdrawing Member shall pay such costs or expenses it owes within 30 days after receiving an invoice from SPP. SPP shall pay the withdrawing Member any monies it owes that Member within 30 days after the withdrawal became effective. The withdrawing Member or SPP may net the amounts due it by any amounts it owes.

4.2.3 Construction of Facilities

Obligations relating to the construction of new facilities pursuant to an approved plan of SPP shall be renegotiated between SPP and the withdrawing Member, where applicable. If such obligations cannot be resolved through negotiations, they shall be resolved in accordance with SPP dispute resolution procedures.

4.2.4 Regulatory and Other Approvals or Procedures

The withdrawal by a Transmission Owner of its facilities from SPP shall also be subject to applicable federal and state law and regulatory approvals or procedures.

5.0 Regulatory, Tax, And Other Authorities

5.1 Regulatory and Other Authorities

This Agreement and the participation of the signatories is subject to acceptance or approval by the FERC and may be subject to actions of respective state regulatory authorities to which respective signatories may be subject and to the actions of any other governmental body which may affect the ability of any signatory to participate in this Agreement. The following items describe the signatories' rights and obligations in the event regulatory and other approvals or acceptances are not obtained or changes are required.

a. In the event the FERC disapproves or refuses to accept this Agreement or the changes to the Transmission Tariff developed together with this Agreement, then this Agreement shall cease to be effective except that the signatories shall be obligated to attempt expeditiously and in good faith to negotiate a substitute agreement and tariff which address the reasons for such FERC action. If, despite such good faith negotiation, the signatories are unable to produce such a substitute agreement and tariff, then the signatories shall have no further obligations under this Agreement or any filing associated herewith.

b. In the event of any order or decision by the FERC or by a court modifying this Agreement or the Transmission Tariff submitted as part of the initial filing seeking FERC acceptance or approval, that in the judgment of the Member adversely affects it, then such 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. In such event, the Member will in good faith negotiate to determine whether changes should be made to the Agreement or Transmission Tariff to address the reasons for such Member's withdrawal.

5.2 Tax Authorities

If the Internal Revenue Service or any other federal, state, or local taxing authority issues, or fails to issue, any ruling, or imposes any requirement or obligation, in connection with this Agreement on any Member, adverse to such Member (in its sole judgment) or if participating as a Transmission Owner or Member jeopardizes the tax exempt status of any Transmission Owner or Member or any Transmission Owner's or Member's bonds, then such Transmission Owner or Member may, within 30 days of the date of such final order, or a good faith belief of such adverse consequences, withdraw from this Agreement subject to receiving any necessary regulatory approvals. In such event, the signatories, including the withdrawing party, will, in good faith, negotiate to determine whether changes should be made to the Agreement to address the reasons for such signatory's withdrawal.

5.3 Effectiveness as to Certain Members

The effectiveness of this Agreement as to a Member which is a governmental entity and which has outstanding tax-exempt bonds issued to finance, in whole or in part, generation, transmission, or distribution facilities is dependent upon satisfaction or written waiver of the following conditions precedent:

a. Receipt of an unqualified opinion of a qualified bond counsel to the effect that the provisions of this Agreement do not adversely affect the exclusion from gross income of interest on any such outstanding bonds issued to finance generation, transmission, and distribution facilities under the Internal Revenue code of 1986, as amended;

b. Receipt of an unqualified opinion of a nationally recognized bond counsel and general counsel to such governmental entity to the effect that the provisions of this Agreement do not constitute a breach or impairment of, or a default under, any agreement to which such governmental entity is a party, including, but not limited to, its master bond resolution, as amended, and any power sales contracts with its municipal transmission users (if any), as amended, or other agreements;

c. Receipt of a certificate of the trustee for any such outstanding bonds issued for generation, transmission and distribution facilities to the effect that the governmental entity's entry into this Agreement is permitted under the master bond resolution, as amended; and

d. Receipt of an opinion of nationally recognized bond counsel and general counsel to the governmental entity that such governmental entity has full constitutional and statutory authority to enter into this Agreement. In the event that any of the foregoing conditions are not satisfied or waived by a governmental entity, then the adversely affected governmental entity shall promptly give notice of its objections or conditions which have not been satisfied to the other signatories, and the signatories shall expeditiously attempt in good faith to negotiate a substitute agreement.

6.0 Removal Of Members

The Board of Directors may terminate the Membership of any Member for cause including, for example, violation of the SPP Bylaws or nonpayment. Such Board of Directors termination shall be after an affirmative vote consistent with the voting procedures in SPP's Bylaws. A Member terminated by the Board shall comply with the requirements of Section 4.2 of this Agreement as if it has voluntarily withdrawn from the Agreement.

7.0 Effective Date, Duration, And Transition

a. This Agreement shall be effective for any signatory on the Effective Date and shall remain in force until the Member's withdrawal becomes effective under this Agreement or this Agreement is terminated. In the event of termination of this Agreement, all financial obligations incurred and payments applicable to time periods prior to the effective date of such termination shall be honored by SPP and each Member as of the date of termination. In addition, all obligations incurred pursuant to Section 4.2 of this Agreement shall survive such termination.

b. For any Member that prior to the Effective Date of this Agreement executed an agency agreement and/or a membership agreement with SPP, upon the Effective Date of this Agreement those prior agreements shall be considered terminated between the Member and SPP; provided, however, that all provisions imposing obligations on the Member relating to obligations incurred before termination shall survive such termination.

8.0 Open Architecture

Nothing in this Agreement is to be read or construed, in any way, as limiting the ability of SPP to evolve in ways that would improve its efficiency.

~~8~~9.0 Miscellaneous Provisions

~~8~~9.1 Governing Law

This Agreement shall be interpreted, construed, and governed by the laws of the State of Arkansas, except to the extent preempted by the law and/or unless a court with jurisdiction rules otherwise, provided, however, that all matters relating to real property or any interest in realty shall be governed by the laws of the State wherein such real property or interest in realty is physically located.

~~8~~9.2 Successors and Assigns

This Agreement shall inure to the benefit of, and be binding upon Members, their respective successors and assigns permitted hereunder, but shall not be assignable by a Member, by operation of law or otherwise, without the approval of the Board of Directors which approval shall not be unreasonably withheld, except that no Board of Directors approval is required as to a successor in the operation of the Transmission Owner's Tariff Facilities committed to administration by SPP by reason of a merger, consolidation, reorganization, sale, spin-off, or foreclosure, as a result of which substantially all such transmission facilities are acquired by such successor, and such successor becomes a Transmission Owner under this Agreement.

~~8~~9.3 No Implied Waivers

The failure of a Member or SPP to insist upon or enforce strict performance of any of the specific provisions of this Agreement at any time shall not be construed as a waiver or relinquishment to any extent of such Member's or SPP's right to assert or rely upon any such provisions, rights, or remedies in that or any other instance, or as a waiver to any extent of any specific provision of this Agreement; rather the same shall be and remain in full force and effect.

~~8~~9.4 Severability

Each provision of this Agreement shall be considered severable, and if for any reason any provision of this Agreement, or the application thereof to any person, entity, or circumstance, is determined by a court or regulatory authority of competent jurisdiction to be invalid, void, or unenforceable, then the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired, or invalidated, and such invalid, void, or unenforceable provision shall be replaced with a suitable and equitable provision in order to carry out, so far as may be valid and enforceable, the intent and purpose of such invalid, void, or unenforceable provision. This Section 9~~8~~.4 does not modify or change in any way the right of a Member to withdraw as provided elsewhere in this Agreement.

9~~8~~.5 Renegotiation

If any provision of this Agreement, or the application thereof to any person, entity or circumstance, is held by a court or regulatory authority of competent jurisdiction to be invalid, void, or unenforceable, or if a modification or condition to this Agreement is imposed by a regulatory authority exercising jurisdiction over this Agreement, then Members and SPP shall endeavor in good faith to negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligations of the signatories under this Agreement immediately prior to such holding, modification, or condition. If after sixty days such negotiations are unsuccessful, then Members or SPP may exercise any individual or collective withdrawal or termination rights available under Sections 4 and 5 of this Agreement.

9~~8~~.6 Representations and Warranties

Each Member and SPP represents and warrants to other signatories that as of the later of the date it executes this Agreement or the Effective Date of this Agreement:

a. It is duly organized, validly existing, and in good standing under the laws of the jurisdiction where organized.

b. Subject to any necessary approvals by federal or state regulatory authorities of SPP, the execution and delivery by each Member and SPP of this Agreement, and the performance of its obligations hereunder have been duly and validly authorized by all requisite action on the part of the signatories and do not conflict with any applicable law or with any other agreement binding upon the signatories, other than third party joint agreements covered in this Agreement. This

Agreement has been duly executed and delivered by Members and SPP, and, subject to the conditions set forth in this Agreement, constitutes the legal, valid, and binding obligation on the part of each Member and SPP, enforceable against it in accordance with its terms except insofar as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium, or other similar laws affecting the enforcement of creditor's rights generally, and by general principles of equity regardless of whether such principles are considered in a proceeding at law or in equity.

c. There are no actions at law, suits in equity, proceedings, or claims pending or, to the knowledge of each Member or SPP, threatened against the Members or SPP before or by any federal, state, foreign or local court, tribunal, or governmental agency or authority that might materially delay, prevent, or hinder the performance by such entity of its obligations hereunder.

9~~8~~.7 Further Assurances

Each Member and SPP agree that it shall hereafter execute and deliver such further instruments, provide all information, and take or forbear such further acts and things as may be reasonably required or useful to carry out the intent and purpose of this Agreement and as are not inconsistent with the provisions of this Agreement.

9~~8~~.8 Delivery of Notices

Except as otherwise expressly provided herein, notices required under this Agreement shall be in writing and shall be sent to each Member or SPP by U.S. mail, overnight courier, hand delivery, facsimile, or other reliable electronic means. Any notice required under this Agreement shall be deemed to have been given either upon delivery, if by U.S. mail, overnight courier, or hand delivery, or upon confirmation, if given by facsimile or other reliable electronic means.

9~~8~~.9 Entire Agreement

This Agreement, the Bylaws, SPP Criteria, and the Transmission Tariff, and their duly approved replacements, constitute the entire agreement among Members and SPP with respect to the subject matter of this Agreement, and no previous oral or written representations, agreements, or understandings made by any officer, agent, or employee of any Member or SPP shall be binding on any such Member or SPP unless contained in this Agreement, the Bylaws, SPP Criteria, the Transmission Tariff, or the Agency Agreement.

9~~8~~.10 Good Faith Efforts

Each Member and SPP agree that it shall in good faith take all reasonable actions necessary to permit it and other signatories to fulfill their obligations under this Agreement. Where the consent, agreement, or approval of any Member or SPP must be obtained hereunder, such consent, agreement, or approval shall not be unreasonably withheld, conditioned, or delayed. Where any Member or SPP is required or permitted to act, or omit to act, based on its opinion or judgment, such opinion or judgment shall not be unreasonably exercised. To the extent that the jurisdiction of any federal or state regulatory authority applies to any part of this Agreement and/or the transactions or actions covered by this Agreement, each Member and SPP shall cooperate with all other signatories to secure any necessary or desirable approval or acceptance of such regulatory authorities of such part of this Agreement and/or such transactions or actions.

9~~8~~.11 Third Party Joint Agreements

This Agreement, the Bylaws, and the Transmission Tariff shall not be construed, interpreted, or applied in such a manner as to cause any Transmission Owner to be in material breach, anticipatory or otherwise, of any agreement (in effect on the later of the Effective Date of this Agreement or the date that it becomes a Transmission Owner under this Agreement) between such Transmission Owner and one or more third parties who are not signatories (regardless of the inclusion of one or more other Transmission Owners as parties to such agreement) for the joint transmission, operation, or maintenance of any electrical facilities covered by this Agreement or the Transmission Tariff. A Transmission Owner who has such a third party joint agreement shall discuss with the Board of Directors any material conflict between such third party joint agreement and this Agreement, the Bylaws or the Transmission Tariff raised by a third party to such joint agreement, but the resolution of such a conflict shall be and remains within the sole discretion of such signatory; provided, however, that such signatory shall, if otherwise unresolved, utilize the available remedies and dispute resolution procedures to resolve such conflict, including, but not limited to, submitting such conflict to the FERC for resolution; provided, further, that in no event shall such signatory enter into a resolution of such conflict which would impair the reliability of the Electric Transmission System.

9~~8~~.12 Amendment

This Agreement may be amended by SPP's Board of Directors, subject to receiving any necessary regulatory approvals. The signatories to this Agreement agree to be bound by this Agreement as it may be amended, provided that the signatories possess the right to challenge any amendments at FERC and to exercise any withdrawal rights that they possess under this Agreement if they are dissatisfied with the amendment.

9~~8~~.13 Counterparts

This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument, binding upon all of the Members and SPP, notwithstanding that all such Members, and SPP may not have executed the same counterpart.

IN WITNESS WHEREOF, the Member and SPP have caused their duly authorized representatives to execute and attest this Agreement, on their respective behalves.

MEMBER:

____.
Name of Member

____.
Type of Entity (Transmission Owner or Non-Transmission Owner)

____.
Name of Authorized Representative

____.
Title of Authorized Representative

____.
Signature of Authorized Representative

____.
Date of Execution

SOUTHWEST POWER POOL, INC.:

Nicholas A. Brown .
Name of Authorized Representative

Vice President and Corporate Secretary .
Title of Authorized Representative

____.
Signature of Authorized Representative

July 26, 1999 .
Date
k:\spp\tariff\membership-agencyagreement799

ATTACHMENT No. 1

COMPARISON OF CONGESTION MANAGEMENT MECHANISMS

	LMP/FTRs	Flowgates/FGRs	Zones/PTRs
Definition of the Basic Models and Processes	The RTO operates an integrated dispatch/spot market process that determines market-clearing energy prices at every node based on the actual security-constrained dispatch. These prices are used to settle energy imbalances, to price congestion for both spot and contract transactions and to settle point-to-point “financial transmission rights” (FTRs) that are allocated and/or auctioned by the RTO. When it is efficient and practical to do so, ancillary services are procured and priced by the RTO as part of this same integrated dispatch/pricing process.	The RTO determines a few(?) transmission constraints that are “commercially significant,” defines the “flow factors” indicating how injections at each node affect flows across each “flowgate,” and allocates/ auctions “flowgate rights” (FGRs) for each flowgate. Market participants trade energy and FGRs among themselves and then submit balanced bilateral schedules that are consistent with their FGRs and the flow factors. The RTO then uses some (market?) process(es) to redispatch generation in real time to deal with residual congestion and contract imbalances. The costs of meeting any constraints not represented by the few(?) flowgates are “socialized” or spread across the market. As far as practical, ancillary services are procured in separate and even non-RTO markets.	The RTO determines a few(?) pricing zones within which LMP differences are not “commercially significant” and then defines and allocates/auctions “physical transmission rights” (PTRs) on each of the interfaces (lines?) between zones. Spot (unscheduled) trading may be allowed at the uniform, RTO-determined settlement price within each zone, but interzonal trades must be scheduled with the RTO consistent with PTRs held by the traders. The RTO manages intrazonal congestion and interzonal flows by making constrained on/off payments to generators redispatched out of merit. As far as practical, ancillary services are procured in separate and even non-RTO markets.
RTO Processes Needed for System Operations	Accurate model of physical system and operational limits for operational purposes. Agreed bidding/market clearing/ pricing/settlement process for integrated energy/transmission/ ancillary service market. Software for integrated security-constrained dispatch/market clearing/LMP calculation and for financial settlements. [***Note:*** *In an LMP system, FTRs*	Accurate model of physical system and operational limits for operational purposes. Agreed bidding/pricing/settlement process for (separate?) balancing, congestion management and ancillary service market(s). Scenarios reflecting the likely range of commercial actions and outcomes. Selection of initial “commercially significant” flowgates for each commercial scenario. Definition of the flow limits and flow factors for each flowgate, perhaps for each of several commercial scenarios (e.g., seasonal or diurnal	Accurate model of physical system and operational limits for operational purposes. Agreed bidding/market clearing/ pricing/settlement process for (separate?) balancing, congestion management and ancillary service market(s). Scenarios reflecting the likely range of commercial actions and outcomes. Selection of initial zones within which LMP differentials are not “commercially

	LMP/FTRs	Flowgates/FGRs	Zones/PTRs
	have no effect on, and hence do not have to be defined prior to, system operations or pricing; nor must they be redefined every time efficient or reliable operations change. In a flowgate/zonal system, the FGRs/PTRs play a central role in the scheduling and dispatch process and hence must be defined prior to operations and then redefined whenever—or before – a "commercially significant" change occurs.]	generation/load patterns). Initial allocation of flowgate rights (FGRs) for each scenario. Process (Market?) for identifying non-flowgate congestion, redispatching generation to resolve it, and making constrained-on/off payments to redispatched generators. Process (Market?) for determining balancing and ancillary service prices in different regions (or at different nodes, since each node has its own flow factors) separated by flowgates. Process for deciding when non-flowgate congestion is "commercially significant," for redefining flowgates, flow-factor tables and FGRs accordingly, and for allocating the redefined FGRs among current and new FGR holders."	significant." Definition of the flow limits across interfaces (lines?) between zones, perhaps for each of several commercial scenarios (e.g., seasonal or diurnal generation/load patterns). Initial allocation of physical transmission rights (PTRs) for each scenario. Market process for determining the uniform energy price in each zone and the scheduled flows between zones. Process (Market?) for deciding which generation should be redispatched to resolve intrazonal congestion and manage interzonal flows, and for making constrained-on/off payments to redispatched generators. Process for redefining zones, flow limits and PTRs when unanticipated congestion arises.
RTO Role in Trading	The RTO's spot energy market automatically provides the physical reference/imbalance prices needed to support efficient energy trading and contracting. In a "net pool" the RTO provides the service of tracking and settling bilateral contracts. In a "gross pool" the RTO simply prices and settles all physical flows (and FTRs) at LMPs, and bilateral energy contracts are financial "contracts for differences" (CfDs) that are settled between the parties with no involvement of the RTO.	The alleged advantage of a flowgate system is that it supposedly allows (i.e., requires) market participants to trade energy and FGRs in decentralized contract markets that do not involve the RTO. In fact, however, the RTO must somehow manage ancillary services, imbalances and congestion in real time (at least), and the most efficient and effective way to do this is with some sort of market process. It is unclear how – or if – these real-time markets would work in a flowgate system without either being unacceptably discriminatory and inefficient or essentially implementing an LMP-like system. Indeed, some flowgate advocates propose that the RTO operate a real-time LMP market, albeit	The RTO must operate a spot energy market that determines the uniform settlement price in each zone and scheduled interzonal flows. This can be either a net pool that tracks and settles bilateral energy contracts (as in Australia and California) or a gross pool that prices and settles all physical flows at the market price and uses financial CfDs for bilateral contracting (as in the UK Pool). Either way, the uniform zonal prices will not reflect intrazonal congestion and hence will create price incentives that the RTO will have to override with some other, less-market-based process.

	LMP/FTRs	Flowgates/FGRs	Zones/PTRs
	no involvement of the RTO. Volatile congestion pricing creates commercial (but not operational) risks that the RTO can reduce by allocating or auctioning FTRs. The RTO can use an auction process to determine the most commercially valuable set of long(er)-term FTRs that is "simultaneously feasible," perhaps for each of several commercial scenarios (e.g., seasonal or diurnal generation/load patterns). The RTO may operate a short-term (e.g., day-ahead) market in which it buys or sells FTRs when actual grid conditions differ from those assumed in the long(er)-term FTR auctions. But because FTRs have no operational implications, such a market is not required for operational purposes and may not be very important commercially. The FTRs auctioned initially can reflect expected conditions without a (large) safety margin, and can provide reasonable financial hedges even if they do not exactly	without explaining how a flowgate/FGR/LMP system might work or why it would be better or less complex than a LMP/FTR system. Because the definition of flowgates and FGRs has such a strong effect on physical operations, the RTO will probably be very conservative in defining the number of long(er)-term FGRs initially, and will then usually have to allocate/sell significant amounts of additional short-term FGRs in order to assure that actual transmission capacity is efficiently used. If the RTO is less conservative in allocating long(er)-term FGRs, it must then often buy back excess in the short-term market. Either way, the short-term FGR market will be large and critical to efficient and even reliable operations. Although the alleged advantage of flowgates is that trading can supposedly be decentralized, in practice the short-term FGR markets will probably have to operated by the RTO. The interactions among flowgates are so complex and develop so quickly that decentralized short-term trading is unlikely to be adequate for reliability purposes.	To deal with intrazonal congestion, the RTO must induce some generators to produce more and some to produce less than they would do to maximize their operating profits given the zonal prices and their contracts. This requires some sort of "adjustment market" to identify a reasonably efficient way to resolve congestion reliably and to make the appropriate constrained-on/off payments. Because prices in the adjustment market may differ significantly from the zonal prices being paid for energy at the same time and place, arbitrage between these two markets – which is at best inefficient and can even threaten system reliability – will have to be controlled with various restrictions on trading. As with FGRs and for the same reasons, the number of long(er)-term PTRs in the market at any time will often differ from the actual capacity for interzonal trading at any time. The RTO will have to do a lot of short-term PTR trading to keep the number of PTRs consistent with reliability and economical operations. Decentralized short-term trading of PTRs is unlikely to be efficient enough to meet the RTO's reliability needs, so the RTO will probably have to operate a short-

	LMP/FTRs	Flowgates/FGRs	Zones/PTRs
	match physical operations.		term PTR market itself.
The Effects of Changing Market or Grid Conditions	In an LMP/FTR market, unlike in the others considered here, the market reflects and prices essentially all congestion, transmission rights play no role in physical operations, and the RTO can honor all transmission rights under a wide range of commercial conditions – e.g., the location of low-cost generation relative to load – with little or no operational or financial risk. As a result, market conditions can change significantly without requiring the RTO to do anything in response except determine the dispatch, LMPs and settlement payments that reflect the new conditions. Any new congestion is priced in the market, so that users without FTRs pay for it while users with FTRs do not; there is no need for the RTO to tax "innocent" system users to pay for new congestion. Although it is not necessary for the RTO to do anything in response to market changes, as a service to market participants the	Because the selection of flowgates and definition of FGRs has such a large effect on system operations and RTO costs, the RTO must define these parameters before the market can begin operating, which requires the RTO to forecast what will and will not be "commercially significant" in the new market conditions. It is notoriously difficult to forecast even short-term commercial outcomes, particularly in a newly-created market, so the initial flowgates are likely to prove inadequate quickly. Even if the initial flowgates and FTRs are adequate, changes in the distribution of generation and loads over time – even with no changes to the grid itself – will cause new (or just different) constraints to become "commercially significant." And, of course, if the physical grid changes, the RTO must – for operational, not just commercial reasons – redefine the flowgates and FGRs. Thus, the RTO will need – probably much sooner than expected – a process for deciding when the existing set of flowgates is no longer adequate, defining a new (and probably larger) set of "commercially significant" flowgates and associated FGRs, and allocating the new FGRs among existing and new FGR holders.	As with flowgates and FGRs, the definition of zones and PTRs has strong effects on system operations and RTO costs, and is based on forecasts of market conditions, not just on grid conditions. As market conditions change – e.g., as the location of low-cost generation changes over the years or seasons or hours – LMPs will change everywhere on the system, and hence the appropriate definition of zones will change. For the same reasons, the interzonal flows that are economical and consistent with reliability criteria will change. The gap between reality and any zonal model that significantly "simplifies" anything will probably be large much of the time soon after the market begins operating and will certainly increase over time even if the grid itself does not change, forcing the RTO to use large side payments that override the market in order to assure reliable operations. And, of course, if the grid itself changes, the appropriate definition of zones and PTRs will almost surely have to change. Thus, the RTO will have to choose between living with an increasingly

	LMP/FTRs	Flowgates/FGRs	Zones/PTRs
	RTO may from time to time operate an auction process to reconfigure the outstanding FTRs to meet commercial needs better. Because FTRs are point-to-point and are based on an accurate model of the entire grid, such a reconfiguration does not affect the rights of any existing FTR holder, i.e., each holder decides for itself whether to keep its existing FTRs or trade them for a better combination. If the physical grid changes, the RTO will probably – again, for commercial, not operational reasons – use a market process to define and allocate an incremental set of FTRs. Again, this can be done without affecting the rights of any existing FTR holders, although the asset value of existing FTRs may be affected by either grid or market changes.	Because a flowgate/FGR system is based on flows and a simplified model of the system, there is no way to change flowgates or FGRs in response to market or grid changes without abrogating the rights of existing FGR holders and/or requiring the RTO to pick up the tab. For example, suppose the RTO adds a new flowgate "X" because the costs of managing congestion on that interface have become too large. In principle, the RTO can hold existing FGR holders harmless in this process by determining how much of the excess scheduled flow on X is due to which transactions by each existing FGR holder, giving each FGR holder the corresponding number of FGRs to use flowgate X, and then buying back enough of these FGRs to reduce scheduled flow on X to the required extent. Even if this is administratively feasible, it requires the RTO to pay out money to existing FTR holders simply because commercial conditions have changed. The fact that the RTO may be able to recover its costs from system users as a group does not make this process efficient or equitable.	inaccurate zonal model of the system with its increasing side payments, and changing the definition of zones and interzonal PTRs. But just as with flowgates and PGRs, this will be a difficult, contentious and virtually continual process. Every proposed change will be strongly resisted by those who will be directly and adversely affected. The RTO can try to buy off the direct opposition and socialize the resulting costs, but this is neither fair nor equitable and is unlikely to be acceptable in the long run. In effect, both a flowgate/FGR system and a zonal/PTR system guarantee a few, large, identifiable, sophisticated users that they will be protected from the commercial effects of all constraints not identified in a highly simplified model of the transmission system. The costs of other constraints are socialized across other – i.e., smaller, less sophisticated – entities. There will be constant pressure from the large, sophisticated users to keep the market model (over)simplified so that more costs are shifted to smaller users through the RTO. The RTO will be caught in the middle.
Requirements for Commercial Trading	In a LMP/FTR system, most energy trading can be, should be and in practice is done under normal bilateral, brokered and exchange-based contracts. Such contracts can be for many years, a few months, a	One of the principal, explicit objectives of a flowgate/PGR system is to assure that virtually all trading is done in decentralized, non-RTO and supposed competing markets. If the RTO deals with much of reality outside the market and socializes the resulting costs, it can create an	Like a flowgate/PGR system, a zonal/ PTR system is often advocated as a way for the RTO to create (and subsidize) an artificial world that is simple enough to be handled by decentralized trading. Use of the RTO's real-time market is sometimes made difficult or

	LMP/FTRs	Flowgates/FGRs	Zones/PTRs
	week, a day or even less, depending on the technology and costs of trading. Contracts in a LMP/FTR system can be as "physical" as they can be in any other system, in the sense that a contract can require either party to do anything that party freely agrees to do and that can be enforced under normal commercial law. Of course, in reality any contract to deliver electricity over the grid is ultimately "financial," in the sense that a seller can do no more than agree to pay the system charges necessary to get electricity physically delivered to the buyer by the RTO (or ISO/GridCo/TransCo/…). FTRs can be traded in long-term or short-term decentralized markets. The fact that FTRs are point-to-point need not make them illiquid, because they are financial instruments with no operational effect. Sophisticated market makers will learn how to hedge a portfolio of energy contracts with a correlated portfolio of FTRs. The fundamental difference between a LMP/FTR system and the others is that a LMP/FTR system ***allows but does not require*** decentralized short-term trading of energy and transmission. A market participant does not need to trade actively in decentralized day-ahead or hour-ahead markets to try to adjust its	artificial world that is simple enough for decentralized markets to handle. If the RTO is then prevented from operating an open spot market, market participants will have to use the non-RTO markets to match their contracts to their actual physical operations as closely as practical. In a market based on flowgates and PGRs, a generator can sell its electricity only if it contracts to sell energy to a specific (set of) load(s) and then schedules each of these transactions with the RTO. If any of these transactions imply flows across any flowgates, the generator must acquire enough PGRs on all relevant flowgates to cover the contract flows as estimated by the flow factors,. When expected capacities, generation costs and demands change, a new set of contracts and PGRs must be found and traded. Unexpected changes will occur continually, forcing every market participant to update its projections and its energy contract and PGR positions continually – or to contract with somebody who does so on its behalf. If there are only a few flowgates this problem can be handled with modern computers and internet trading. But there can be few flowgates only if the RTO is managing most of reality outside the market or there really are few constraints that can ever be binding – and in this latter case even an LMP/FTR system is simple. If there are more than a few potentially binding constraints and the RTO is not socializing most of the problem, decentralized trading is no match for reality even with computers and the internet. There will be many hours in which some mutually profitable transactions are not concluded because the potential buyers and sellers were unable to find one another quickly or cheaply enough.	costly – e.g., in California – so that traders are forced to use the decentralized forward markets. However, some zonal systems – e.g., Australia – do allow trading in the real-time market operated by the RTO. If the RTO is not allowed to operate an open real-time market, traders must enter into energy contracts that match their expected physical operations, and must acquire PTRs if such contracts involve interzonal trades. If interzonal transactions imply flows across several zonal boundaries it may be necessary to obtain PTRs on several boundaries, based on flow factors equivalent to those used in a flowgate/PGR system. If the number of zonal boundaries in a zonal system is about the same as the number of flowgates in a flowgate system, the short-term trading problems will be essentially the same. If the RTO does operate an open real-time market, trading is somewhat simpler because there is less need to match energy contracts to physical operations. But interzonal trades must still be contracted and matched with PTRs and the RTO must still manage intrazonal congestion and interzonal flows outside the principal markets. If there are only a few, simple potential constraints, a zonal market can be – just as a LMP market can be. But if there are many potential constraints and the RTO does not deal with most of them outside the market, trading in a zonal/PTR system can be just as demanding as trading in a flowgate/FGR system and can have the same result: A single, regulated energy and PTR exchange that might as well

	LMP/FTRs	Flowgates/FGRs	Zones/PTRs
	contract positions to its latest projection of its real-time position, because this is done automatically in the RTO's real-time LMP market at market-determined, transparent prices. Of course, marketers, exchange operators and large, sophisticated players, all of whom may benefit from market inefficiency and opaqueness, often regard such an RTO market as "unfair" competition. But for the principles buying and selling physical electricity – particularly smaller, less sophisticated players – the option to use the RTO's market is a real advantage.	In practice, it is unlikely that competitive short-term market places or exchanges would survive even if they were tried. Centralized trading is so valuable in such situations that only one market or exchange would survive – not because it was necessarily more efficient, but simply because it was the first or largest. Because all market participants and the RTO would have to use the resulting monopoly exchange for the short-term FGR trading that plays such a critical role in system operations, it would have to be closely coordinated with the RTO and would almost surely be subject to FERC regulation. If operations and regulation were coordinated enough to assure reasonable efficiency, the exchange might as well be part of the RTO.	be part of the RTO. In either a flowgate/FGR or zonal/PTR system, the RTO could deal with real-time congestion and imbalances using a real-time market that reflects reality much more accurately than flowgates or zones can. If this real-time market were accurate and efficient enough, private exchange operators could aggregate its prices into a smaller number of zones and its transmission rights into a smaller number of flowgates. Exchanges could then compete for traders' business by offering trading simplicity, efficiency and innovation. But this would require the RTO in effect to operate a real-time LMP/FTR market. And it would require each exchange, not the RTO, to take the risk that its simplifying assumptions were wrong by a "commercially significant" amount.

ATTACHMENT No. 2

Comparison of Locational Marginal Pricing (LMP) Congestion Management (CM) Schemes

	Nodal	**Zonal**	**Flow-based**
Objectives of CM			
Theoretical Efficiency	Sound in theory, in practice dependent on software and input assumptions. (i.e., assumptions and judgement "in the control room")	Efficient with rounding error (determined at design stage), depends on topology of system and patterns of congestion.	Efficient pricing, dependent on efficiency of energy markets and selection of flowgates.
Implementability	Centralization costly. Mixed results in reality - more suitable for 'tight' pools with few control areas.	Easier implementation in large areas with multiple control areas. Challenge lies in zone definition and flowgate selection at design stage.	Selection criteria required for 'commercially significant' flowgates.
Bilateral Market Activity	Complexity, price unpredictability, unmanageability and time required to calculate prices are barriers to entry and trade. Has discouraged bilateral activity in practice.	Encourages bilateral trading, Market participants set price of transmission in exchanges.	Encourages bilateral trading, Market participants set price of transmission.
Equity	Can lead to inequitable outcomes at a local level (e.g., factor of 10 difference in prices in same substation in PJM due to different voltage level), plus consumers pay the price for operator judgements/ decisions (e.g., deferred investments and arbitrary prices when model won't solve)	Equitable in the absence of significant unanticipated intra-zonal congestion (which can be mitigated by adding new zones/flowgates)	Equitable in the absence of significant unanticipated intra-zonal congestion
Cost Allocation	Accurate, within limits of assumptions, highest level of granularity. May unnecessarily penalize loads for transmission problems	Accurate with well-defined zones and constraint selection.	Accurate with appropriate flowgate selection

	Nodal	Zonal	Flow-based
Objectives of CM			
Future Investment	Provides right signals for generation, deters creation of 'local' congestion. Little incentive for transmission investment	Provides right signals, but with less granularity. TransCo can be designed to have incentive for transmission investment (e.g., take risk of intra-zonal congestion)	Provides right signals, but with less granularity. TransCo can be designed to have incentive for transmission investment (e.g., take risk of intra-zonal congestion)
Retail Access	Complexity and illiquidity in FTRs and ex-post pricing can hinder retail participation. Retail providers will have dynamic portfolios that will need liquidity and simplicity in trading	Effective, because of commercial simplicity in defining physical rights and offering limited pricing areas	Effective, because of commercial simplicity in defining physical rights and automating portfolio management in bilateral markets
Methodology			
Transmission Property Rights			
Definition	Financial Rights, defined point-to-point. No flow guarantee, but receive payment for resulting price difference. Physical rights would not be easily definable in a nodal system.	Workable with physical and financial rights - proposed mostly with physical rights - defined for "commercially significant" physical constraints only.	Workable with physical and financial rights - proposed mostly with physical rights - defined for "commercially significant physical constraints only.
Nomenclature	FTRs (Fixed Transmission Rights) in PJM, (Transmission Congestion Contracts) TCCs in New York, (Financial Congestion Rights) FCRs in NEPOOL	(Firm Transmission Rights) FTRs in California	PTRs (Physical Transmission Rights) in the Flow-based model.
Capacity Release	Periodic auctions, capacity released based on auction bids. Auction requires OPF model. Rights can theoretically be traded in secondary markets, though transfers require RTO intervention in NY and PJM, and location-specificity hinders trading. In PJM, quantity-based rationing provides incentives to hoard FTRs.	Capacity auctioned on chosen paths based on simultaneous transfer limits. Incremental capacity released continuously into bilateral market. Continuously cleared bilateral secondary market for capacity through exchange.	Capacity auctioned on chosen flowgates based on individual transfer limits. Continuously cleared bilateral secondary market for capacity through exchange.

	Nodal	Zonal	Flow-based
Handling Loop Flows (within RTO)	Internalized into Optimal Power Flow (OPF)	Handled by defining capacity rights using simultaneously feasible flow limits, and requiring zone-to-zone purchases to purchase rights on flowgates in accordance with distribution factor-based flow contributions	Handled by requiring transactions to purchase flowgate rights based on contribution of transactions to flows on each flowgate. Capacity auctioned based on simultaneously feasible flow limits
Market Operation			
Payment	Payments made to RTO in auctions. In PJM, FTRs can be purchased at embedded cost rates. In secondary markets, financial transaction is purely bilateral.	Payments made to RTO in initial auctions - thereafter, transactions purely bilateral, based on market prices, not cost.	Payments made to RTO in initial auctions - thereafter, transactions purely bilateral, based on market prices, not cost.
Energy Price Calculation	Calculated by RTO ex-post in all markets (real-time and forward) using OPFs at nodal level. Can create hubs (e.g., PJM Western Hub) or have zonal prices for loads (some form of wtd. avg. nodal prices, as in NY). Time required to solve optimization precludes continuously clearing forward markets.	Self-determined ex-ante and continuously in forward markets (bilateral trading or multi-lateral exchanges) In real time, derived from zonal inc. and dec. bid stacks in the balancing market Zones determined in several ways: - In radial systems, based on flowgate locations - In complex grids, based on either distribution factor- or nodal price-clustering	Self-determined ex-ante in forward markets (bilateral trading or multi-lateral exchanges). In real time, workable with nodal or zonal prices - depends on implementation of real-time market.
Bid Structure	Three-part bid (start-up, min. gen, and energy) or one-part bid, in all forward markets. Real-time uses energy and ancillary service bids from day-ahead/hour-ahead markets	No restriction in forward markets, since markets are bilateral. In real-time, single part ancillary service bids and supplemental energy inc. and dec. bids for balancing	No restriction in forward markets, since markets are bilateral. In real-time, use ancillary service bids and supplemental energy inc. and dec. bids for balancing

	Nodal	Zonal	Flow-based
Market Operation			
Forward Markets	- Transmission: secondary market for FTRs - liquidity an issue, given complexity and non-fungible products. Transfer of FTRs require RTO involvement - Energy: Centralized, designated markets (day-ahead, hourly) cleared by RTO using bid-based OPF, no requirement to balance schedules.	Energy, transmission and ancillary services traded in exchanges (e.g., CA PX) where products are continuously traded and cleared bilaterally up until real-time (however defined). Balanced schedules required to be submitted to dispatcher.	Energy, transmission and ancillary services traded in exchanges (e.g., CA PX) where products are continuously traded and cleared bilaterally up until real-time (however defined). Balanced schedules required to be submitted to dispatcher.
Bilateral Activity (energy)	Use contracts for differences (CfDs) against pool prices, bid zero or negative into pool to ensure delivery (all internal bilaterals purely financial) - price and FTR complexity can limit liquidity of bilateral trades for delivery - NY and PJM show poor liquidity of contracts for delivery and much difficulty with wheels, imports, and exports	Dominant form of trade - continuously traded in exchanges. Market simplicity (price and transmission rights) enables high liquidity	Dominant form of trade - through exchanges, continuously traded. Market simplicity (transmission rights) enables high liquidity
Real-time Balancing Market/ Dispatch	Centralized RTO performs real-time security-constrained dispatch, restrictions on external schedules only, deep, liquid real-time market. In NY, real-time prices revised up to 2 weeks ex post.	Control area -level dispatch. Former requires coordination mechanisms among control areas. Real-time market only for balancing	Dispatch can be at the RTO- or control area-level. Real-time market only for balancing
System Expansion			
Siting New Generation	Provides right signals for generation, deters creation of 'local' congestion.	Provides right signals, but with less granularity.	Provides right signals, granularity dependent on use of nodal vs. zonal pricing

	Nodal	Zonal	Flow-based
Transmission Planning	Little incentive for transmission investment	Transco can be designed to have incentive for transmission investment (e.g., take risk of intra-zonal congestion)	Transco can be designed to have incentive for transmission investment (e.g., take risk of intra-zonal congestion)
Institutional Structure			
RTO Role in Forward Markets			
Transmission	- Manage FTR capacity release and auctions and secondary market - Manage single OASIS site	- Define and release transmission capacity in auctions - Manage single OASIS site	- Define and release transmission capacity in auctions - Manage single OASIS site
Energy	Heavy - Operates energy market for all settlement periods	Minimal - No involvement in energy market, except for real-time balancing	Minimal - No involvement in energy market, except for real-time balancing
Ancillary Services	RTO offers all ancillary services, and serves as provider of last report. Depending on implementation, may have ancillary services market (reserves and frequency control) separate from or combined with energy market	- Post ancillary service (reserves) and loss requirements for forward markets - Provider of last resort	- Post ancillary service (reserves) and loss requirements for forward markets Provider of last resort
RTO Role in Real-time	RTO operates as single control area: - Scheduling, system control and dispatch - Reactive supply and voltage support - Regulation and frequency response - Energy imbalance service - Spinning reserve - Supplemental reserve	RTO only coordinates decentralized dispatch at the zone/control area level. RTO performs: - Scheduling - Balancing market - Coordination of dispatchers Control area dispatchers perform all other ancillary services.	Implementation -dependent

	Nodal	Zonal	Flow-based
RTO Structure	Typically not-for profit ISO. For-profit TransCo possible, but conflict of interest due to operation of energy market and transmission system would need resolution	Can be an ISO or a for-profit Transco	Can be an ISO or a for-profit Transco
FERC Objectives			
12 RTO Principles	Conform with all characteristics and functional requirements	Conform with all characteristics and functional requirements	Conform with all characteristics and functional requirements
Market Experience			
	PJM - 4/1/98 NY ISO - 11/18/99 (load-zonal) New England (under development) New Zealand (no FTRs) Peru Argentina Bolivia Chile Mexico (proposed) UK - (abandoning centralized approach in '00)	California - 4/1/98 (zonal-financial) Mountain West ISA (proposed zonal) Desert Star - (proposed flowgate/ zonal) Australia (state-based zones) Norway (dynamic zones) ERCOT - (proposed flowgate/zonal)	Desert Star - (proposed flowgate/ zonal) ERCOT - (proposed flowgate/zonal)

Acronyms:

PTR: Physical Transmission Right
FTR: Financial Transmission Right
CA PX: California Power Exchange
ISO: Independent System Operator
ISA: Independent Scheduling Administrator
RTO: Regional Transmission Operator
OPF: Optimal Power Flow
CFD: Contract for Differences

SPP Objectives - Comparison of CM Approaches

1. Efficient Use of Existing Assets
   Comparable across CM schemes.

2. Efficient Signals for New Investments (Transmission & Generation)
   Comparable efficiency for siting generation. Nodal offers higher granularity, but with appropriate flowgate selection, the zonal and flowgate approaches offer equivalent efficiency. ISO institutional structure provides little incentive for transmission investments. The zonal/flowgate could be implemented with a for-profit Transco, which could have incentives to investment in transmission (e.g., by bearing intra-zonal congestion risks). Nodal would be difficult to implement with a Transco, due to the conflict of interest inherent in running both an energy market and the transmission system.

3. Efficient Real-Time Price Signals
   Comparable across CM schemes. Nodal would have more efficient (least-cost) real-time dispatch, due to use of a system-wide OPF, but requires and assumes participant generators bid into the centralized pool efficiently. In the zonal approach, the real-time market is only a balancing market, consisting of a very small percentage of overall transactions. Inefficiencies in dispatch would arise in rare, emergency-type situations and therefore be virtually negligible. The flowgate approach is indifferent to the implementation of the real-time market.

4. Fair Risk Allocation
   In the nodal approach, market participants bear an unnecessary and undue amount of transmission risk. That is, the price granularity exposes the user to the price impacts of every possible physical system characteristic and operator action. For example, geographically co-existent loads can pay totally different prices due to properties of the grid. In the zonal approach, users are shielded from this risk. However, market participants do bear the risk of bearing socialized congestion costs in the event of significant intra-zonal congestion. This would only arise if undefined flowgates experience significant congestion, which can be prevented simply by defining new flowgates.

5. Lowest Cost
   The administrative, operating and capital investment costs to centralize 17 control areas required by the nodal approach would be almost prohibitive. A flow-based approach can preserve existing control areas and would minimize the role, and therefore the set-up and operating costs, of an RTO. Indirect costs are also higher in a nodal approach due to the learning curve associated with a bid-based, centralized pool.

6. Forward Market Liquidity - Ex Ante Pricing
   In the nodal approach, the complexity of transmission rights (point-to-point between thousands of nodes) inhibits liquidity in the secondary market for FTRs, and therefore impedes bilateral trading in forward markets. This effectively restricts the bulk of activity to an ex-post, real time market. The zonal and flowgate approaches provide ex-ante pricing in continuously traded energy and transmission markets, which deal with few prices and flowgates. The bulk of activity in these approaches will take place in forward markets.

7. Price Certainty
   The liquidity in forward markets provides price certainty to traders, just as it does in other commodity markets. This is more likely to be present in the zonal and flowgate approaches than in the nodal

approach. The zonal approach has the added element of certainty provided by node aggregation, since market participants are shielded from unnecessary and unpredictable price volatility. This is particularly beneficial with retail competition, where market participants will face less transmission and price risk in managing dynamic portfolios.

8. Timely Implementability
   Centralization of 17 control areas, as required in the nodal approach, in SPP's expected time frame is virtually impossible. A flow-based or zonal approach that preserves control area-level dispatch can allow timely implementation, with the ability to create zones or nodal regions, if appropriate, in the future. In the zonal approach, the coincidence of control areas and zones would ease implementation.

9. Market-based CM
   Comparable across CM schemes in principle. However, the potential absence of liquidity in forward markets in the nodal approach impedes development of wholesale energy markets.

10. Flexibility and Responsiveness to Market Needs
    The nodal approach is a one-size-fits-all approach. Centralization of control areas will be required, and the RTO will have to operate the energy market. The flow-based and zonal approaches allow a step-wise and flexible design that can be tailored to meet SPP's needs.

11. Integration with Market Settlement System
    Comparable across CM schemes.

12. Compatibility with Retail Competition
    Market complexity in the nodal approach would significantly hamper retail competition. Ex-ante pricing and commercial simplicity of the flow-based and zonal approaches would be beneficial to retail choice.

13. Operational Efficiency and Administrative Feasibility
    The bureaucracy of a centralized ISO would require high operational costs. The operational costs of a zonal and flowgate approach would be significantly lower.

14. Seams Issues
    Comparable across CM schemes.

15. Allowance for Demand-Side Bidding
    Comparable across CM schemes.

16. Potential for Gaming
    Comparable across CM schemes.

ATTACHMENT No. 3

Questions about Congestion Management

In the Southwest Power Pool

The following are APX's responses. For consistency with the other set of questions we are answering concurrently ("Questions and Answers for Understanding Flow-Based Scheduling"), we use the term "Flow-Based Scheduling" to identify the particular decentralized congestion management system that has been proposed by APX and other parties. In the presentation by Ed Cazalet of APX to the SPP, this same system was called the "True Flow" approach. Also, note that the "flowgate rights" referred to here are the same as the "Physical Transmission Rights" or PTRs referred to in the other set of questions.

1. What is the cost of congestion management in SPP and Entergy today?
   - How many MWH's of transactions are curtailed each year?
   - How many transactions did not occur due to the presence of congestion?
   - How much has redispatch cost SPP and Entergy in the past year?

2. How centralized would dispatch in the SPP have to be to implement a zonal scheme? How much centralization is needed to implement a nodal approach?

   Under the Flow-Based Scheduling system, no consolidation of control areas would be required. Consolidation can be accommodated if there are reasons other than congestion management to do so. The Flow-Based Scheduling system provides for pricing of flowgate constraints, which can accommodate either zonal or nodal energy pricing systems.

– How much would it cost to consolidate 17 control areas into one?

3. How much will a transition to a nodal, zonal, or flow-based congestion management scheme cost?

   Because the Flow-Based Scheduling system does not require consolidating control areas, and because it relies on bilateral and exchange trading of energy, flowgate rights, and ancillary services, the costs of the Flow-Based Scheduling system should be much less than other alternatives.

– How much training, cost and adjustment would be required to transition to the bid-based, centralized pool necessary for a nodal system?

– How much training and investment would be required to develop and operate independent exchanges for energy, ancillary services, and transmission rights?

   – *The costs of the Flow-Based Scheduling system will be shown in our proposal.*

4. How will the bilateral markets be affected by a change in the congestion management system?

   Under the Flow-Based Scheduling system, bilateral customers would continue to be able to lock-in the cost of congestion in advance. This is not true of the LMP approaches without resort to separate financial hedging instruments. All of the systems under consideration would eliminate curtailments except under extreme emergency conditions

   .

– Could we retain our present bilateral-based transaction structure in a zonal scheme? Could we in a nodal scheme?

   Under the LMP approaches, participants would need to engage in separate financial hedges in order to lock-in a cost of transmission in advance. Under the Flow-Based Scheduling system, the bilateral-based transaction structure would be little changed.

5. How will retail competition impact our decision criteria for congestion management?

   Direct retail access provides a great opportunity to increase the amount of demand price response in the market. This demand price response will only become significant, however, to the extent that prices can be known in advance. Therefore, an important decision criteria for congestion management should become the extent to which the system can provide forward price information to retail customers.

   .

6. Could a nodal approach co-exist within a zonal scheme in different parts of the same RTO?

   The Flow-Based Scheduling system can allow zonal and nodal pricing based on flowgate prices within the same RTO.

7. Could curtailments occur regardless of the existence of any congestion management system? Are they more likely to occur under one congestion management approach or another?

   All of the systems under consideration would eliminate curtailments within SPP except under extreme emergency conditions. We see no reason to expect the number of curtailments to differ between systems.

8. To what extent does each method provide price certainty? To what extent is price certainty only available through entering into a financial hedge?

   The Flow-Based Scheduling system provides certainty for the congestion costs of the commercially significant constraints without resort to separate hedging instruments.

9. What measuring points do we have available now? What is currently available from metering already installed?

10. Where on the SPP system can we expect to have TLR's?

    TLRs should not be necessary under any of the proposed systems except under extreme emergency conditions, or on transactions that cross control areas still using the contract path approach.

11. Is it possible to design a system that can be scaled in accordance with the magnitude of the problem on the SPP system?

    Under the Flow-Based Scheduling system, the number of flowgates traded in the market could be increased or reduced depending upon the number of commercially significant constraints on the SPP system. The Flow-Based Scheduling system could also evolve from a zonal to a nodal-based system depending upon the magnitude of the congestion.

12. How will the devised congestion management system operate with respect to current transmission contracts that do not provide for application of a congestion charge?

    Dealing with current transmission contracts is a policy issue that can be dealt with through the initial allocation of flowgate rights. Under the Flow-Based Scheduling approach, holders of current transmission contracts could be effectively shielded from congestion charges though an appropriate initial allocation of flowgate rights. How transmission rights should be initially allocated is an issue in all the proposed congestion management systems. It can, and should, be separated from the issue of which congestion management system to adopt.

13. Can LMP work in a multi-control area environment? If so, how?

14. What CM system provides the lowest cost to load?

    Because the Flow-Based Scheduling approach provides solid forward price information to allow generators the time to commit and dispatch most efficiently, and loads the time to respond to price changes, it should offer lower cost to loads than the other approaches. Also, since the Flow-Based Scheduling approach opens most market administration functions to competitive vendors, there will be greater incentives for innovation and cost reduction.

15. Which of the system types can we implement within the time frame we have? What time frame is required to implement each of the various CM system options, given the nature and current configuration of SPP infrastructures and institutions? Time, as well as cost, is a constraint on our selection of a CM system.

    The Flow-Based Scheduling approach should be the simplest and quickest to implement, since it requires the least amount of market involvement from the RTO. Since SPP is already very familiar with use of flow-based analysis, the Flow-Based Scheduling system best makes use of existing SPP infrastructure.

16. What system analysis tools are available to assist us with an analysis of the entire SPP system?

17. What obligation (s) must generators accept in order to have an effective CM system?

    Because the Flow-Based Scheduling system relies on price incentives, there should be no need for obligatory actions by generators in the absence of emergency conditions or market power,

18. Is there a migration path from one methodology to another. For example, can we move from zonal to nodal or vice versa, in the future?

Since both the Flow-Based Scheduling approach and traditional LMP could use real-time dispatch as a balancing market, it would be possible to move from one to the other simply by replacing one forward market approach with the other (forward flowgate markets in the Flow-Based Scheduling approach vs. multi-settlements and FTRs in traditional LMP).

ATTACHMENT No. 4

QUESTIONS AND ANSWERS FOR UNDERSTANDING FLOW-BASED SCHEDULING

The following are APX's responses. Note that one of the questions refers to "PTRs" (Physical Transmission Rights), whereas we use the term "flowgate rights" to describe the same concept.

A. WHAT ARE THE BASIC ELEMENTS THAT DESCRIBE HOW FLOW-BASED SCHEDULING WORKS?

1. F~~Physical transmission rights (PTRs~~lowgate rights~~)~~ are initially auctioned by the RTO. These ~~PTRs~~flowgate rights entitle the holder to use a stated amount of transmission capacity on a specified flowgate.

2. Through e-commerce, ~~PTRs~~flowgate rights can be traded in secondary markets at prices derived from bids and offers. Changes in ownership of ~~PTRs~~flowgate rights through such secondary market trades are electronically communicated~~transferred~~ to the RTO.

Flowgate rights can also be created by transmission customers who schedule counterflows on a flowgate. These additional flowgate rights may also be traded in the secondary market.

3.

4. In order to schedule ~~firm~~ transmission service, the transmission customer must have the requisite ~~PTRs~~flowgate rights at the RTO. As a service for participants who wished to schedule transactions, but had not acquired the needed flowgate rights in the forward market, the RTO could offer a near real-time procurement of flowgate rights. The RTO would, in real time (after the scheduling deadline), create through redispatch the needed flowgate rights, and bill customers for the associated costs. Customers could thus be assured that their transactions would always flow.

5. In order to give customers an incentive to schedule their transactions in advance, flowgate rights would be subject to a "use it or lose it" rule. Specifically, any flowgate right not filed with a schedule prior to the scheduling deadline would revert to the RTO without compensation. A customer who owned flowgate rights that he/she did not wish to use would, of course, be free to sell them to another customer in the secondary market prior to the scheduling deadline.

B. HOW DOES THE TRANSMISSION CUSTOMER KNOW WHICH FLOWGATES AND FLOW-GATE CAPACITIES ARE REQUIRED FOR A GIVEN TRANSACTION?

1. Information on which flowgates are impacted by various potential ~~a specific~~ transactions, and in what amounts, would be electronically posted ~~provided~~ by the RTO.

~~2.This information can be provided at the RTO web site, where the transmission customer designates the source, sink and amount of the transaction.~~

~~3.~~2.~~The RTO will need to have computer software developed that can respond to such requests, giving the flowgate impacts associated with any specified transaction.~~Exchange operators and software vendors would provide software to allow customers to identify the best energy transactions, taking into account the cost of the needed flowgate rights, and to allow customers to track the flowgate rights that their energy transaction portfolios require.

C. DOES THE AMOUNT OF TOTAL CAPACITY ON A FLOWGATE CHANGE?

1. Flowgate capacity is defined as: ***the operating security limit~~maximum megawatts~~ that limits the net flow ~~the RTO can allow to flow~~ across a flowgate at any point in time***. Flowgate capacities are directional, and ~~can result in~~ the capacities in opposite directions across a given flowgate may be~~ing~~ different.

2. The ~~amount of total~~ flowgate capacity ~~on a flowgate~~ depends primarily on the physical conditions of the transmission network, rather than the flows on the transmission network.~~can change with changing conditions on the transmission system.~~ These changes usually can be easily accommodated in the market. For example:

   ~~a.Flows in one direction across flowgates can increase the capacity that can be allowed to flow in the opposite direction.~~

   ~~b.For load levels specified at sinks throughout the RTO, changing the levels of generation at the various sources can result in changes to the flowgate capacities.~~

   ~~c.~~a. At various times, portions of the transmission system may be on planned outages~~out of service~~, and this will reduce~~change~~ the flowgate capacities, but the RTO can initially withhold flowgate rights corresponding to the planned capacity reduction.

   b. Changes to the network configuration due to unplanned outages may also affect flowgate capacities, but these can be largely accommodated by having the RTO initially withhold some flowgate rights until it becomes reasonably clear that the flowgate capacity will actually be available.

~~3.~~3. ~~In summary, flowgate capacities are dynamic (constantly undergoing change), not static (constant without change).~~

3. Since the operating security limit on a flowgate is the limit on net flows, counterflows in the uncongested direction will result in an opportunity to flow more in the congested direction. Parties who create counterflows will therefore have the opportunity to use or sell the corresponding quantity of flowgate rights in the congested direction.

D. IF FLOWGATE CAPACITIES ARE DYNAMIC, HOW DOES FLOW-BASED SCHEDULING DEAL WITH THIS UNCERTAINTY?

~~1.In order to deal with changing capacities for flowgates, there needs to be a differentiation between "firm" PTRs and non-firm use of the transmission.~~

~~a.Usage by firm PTRs can vary by time-of-use (seasonal, monthly, weekly and/or daily), but represent an assured availability of transmission capacity (megawatts) across a flowgate in a specified direction.~~

~~b.Non-firm transmission use can also vary by time-of-use, but such use is allowed subject to the availability of transmission capacity across a flowgate in a specified direction.~~

~~2.There are two general methods the RTO can use to deal with requests for non-firm transmission service that exceeds the available transmission capacity on a given flowgate:~~

~~a.Non-firm PTRs:~~

~~1)Have an initial auction for non-firm use of flowgates;~~

~~2)In near real-time allocate the ability to use the flowgate on an administrative basis (i.e., first-come/first-served, proration, etc.); and~~

~~3)Allow holders of non-firm usage rights to work out bilateral arrangements (e.g., generation redispatch and/or trades of non-firm usage rights).~~

~~b.Have a near real-time auction for the ability to use the transmission system when requests for non-firm transmission exceed the available capacity of a flowgate.~~

1. If there are unexpected reductions in flowgate capacities that the RTO is unable to accommodate through withholding flowgate rights from the market to begin with, the RTO could buy back the excess flowgate rights in the secondary market. This is similar to the way airlines deal with overbooking situations.

2. An alternative approach in such overbooking situations would be pro-rata reductions in the capacity of each flowgate right on the flowgate. However, the buyback approach provides greater certainty to buyers of flowgate rights. Hybrid approaches, where the RTO and customers share the risk of a capacity reduction are also possible. Such an approach might require the RTO to buy-back any flowgate rights that cannot be honored, but obligate the transmission customer to sell back at some pre-specified ceiling price.

~~E.~~E. HOW IS CONGESTED USE MANAGED THROUGH NEAR REAL-TIME AUCTIONS WHEN REQUESTS FOR NON-FIRM USE EXCEED THE AVAILABLE CAPACITY OF A FLOWGATE?

~~1. When requests for non-firm use exceed the available capacity on a flowgate, the RTO performs a near real-time auction for use of the congested flowgate. Upon ranking the bids from highest to lowest, the market-clearing price is the lowest bid price consistent with the available flowgate capacity.~~

~~2. With near real-time auctions for non-firm use of flowgates, there are two alternative methods for dealing with the distribution of revenues collected by the RTO from these auctions.~~

~~a. The revenues from the near real-time auctions are directly used to offset the revenue requirements of the transmission owners. In this approach, the transmission customers have no way to hedge against potential high costs for non-firm use of the transmission system.~~

~~b. The RTO has an initial auction for financial transmission rights (FTRs) for non-firm use of congested flowgates. The holders of FTRs are entitled to receive a prorated amount of the revenues collected by the RTO in its market for non-firm use of the congested flowgate. Like PTRs, FTRs can be traded in secondary markets. However, unlike PTRs where the capacity is fixed, the percentage of revenues that will be received by the FTR holder will depend on the total quantity of FTRs initially sold relative to the actual flowgate capacity available for non-firm use.~~

1. An advantage of both LMP and the Flow-Based Scheduling approaches is that there is only one class of transmission, "firm". This simplifies the market by reducing the number of tradeable transmission rights. Therefore, the issue becomes what happens when requests for firm use exceed available capacity?

2. As explained in A.4 above, the RTO could offer a near real-time procurement of flowgates to provide flowgate rights to any participant who needed them to support their transactions, but had not acquired them in the forward market.

~~F.~~F.

HOW IS CONGESTED USE MANAGED WHEN SCHEDULES BY HOLDERS OF ~~PTRs~~PTRS EXCEED THE AVAILABLE CAPACITY OF A FLOWGATE?

~~1.~~1. The RTO policy should be not to issue ~~PTRs~~flowgate rights (PTRs) in excess of the available capacity of the flowgates under planned ~~"normal"~~ conditions, and not to release flowgate rights to the market until it is reasonably clear that they can be honored~~. Such a policy needs to carefully specify what is meant by "normal" conditions.~~

2. When unplanned~~abnormal~~ conditions occur, it is possible that the amount~~capacity~~ of the ~~PTRs~~flowgate rights issued will exceed the available capacity on one or more flowgates. In this case, the RTO should buy back the flowgate rights that cannot be honored in the open secondary market.

~~3.As with non-firm transmission congestion, there are two general methods the RTO can use to deal with schedules for firm transmission service that exceeds the available transmission capacity on a given flowgate.~~
~~a.Allocate the ability to use the transmission system on an administrative basis (i.e., first-come/first-served, proration, etc.) and allow holders of the PTRs to work out bilateral arrangements (e.g., generation redispatch and/or trades of PTRs).~~

~~b.Apply the same transmission auction used for non-firm transmission to firm transmission, with PTRs functioning the same as FTRs; i.e., holders of PTRs are given prorated shares of the revenues collected in the auction by the RTO.~~
3. Curtailment of scheduled transactions should be necessary only in extreme emergency situations.~~.~~

~~F.~~G. HOW DO TRANSMISSION OWNERS RECOVER THEIR REVENUE REQUIREMENTS UNDER FLOW-BASED SCHEDULING?

1. Load serving entities ~~(LSEs)~~ and/or generators ~~(GEN)~~ are charged access fees to recover the embedded cost-based revenue requirements of the transmission owners ~~(TOs)~~.

2. Revenues received from ~~1)~~ the initial RTO auctions for flowgate rights~~firm~~ less the cost of any buybacks of flowgate rights that cannot be honored ~~PTRs and 2) either non-firm PTRs or FTRs~~ are used to offset the embedded cost-based revenue requirements and lower the access charges.

3. With the exception of an administrative fee, the RTO does not apply any additional charges for transmission service.

4. The Transmission Owners can thus be guaranteed that they will recover their revenue requirements.

ATTACHMENT No. 5

Coral's Responses to Dave McNabb's Questions
about Flow-based Scheduling and Congestion Management (CM)
July 7, 2000

1) **What is the difference between the flowgate method proposed and that currently implemented by the SPP.**

   Two key differences are:

   a) *Congestion is resolved by market mechanisms (bid-based) rather than through rationing (TLRs and socialized redispatch). The benefits are better cost allocation and economically more efficient outcomes (those who value the rights most get them).*

   b) *Transmission capacity rights are traded at market prices, not cost. A liquid secondary market for transmission is therefore expected, unlike today under Order No. 888.*

2) **How will a liquid trading market for these flowgate rights be developed? Why will the market support that instead of the present system where the owner of scarce rights simply charges other parties that need to use the path for the basis difference in the energy price?**

   See Answer 1b). Additionally, the simplicity offered by few commercially significant transmission flowgates and few price points, coupled with user-friendly exchanges to buy energy and transmission rights, will also enhance liquidity. Finally, we understand that the present redispatch system for congestion in SPP is not market-based, and has seldom been used, suggesting that it is not a attractive or viable alternative.

3) **How are the Physical Transmission Rights (PTRs) determined in the initial auction**

   The flow-based approach will define capacity limits based on the simultaneously feasible thermal/stability limits of flowgates. This approach has to be coupled with linking transactions to flowgates based on distribution factors.

4) **Does this set of PTRs have to be simultaneously feasible?**

   Yes, by definition because in the initial auction only those PTRs that can be assured of use under all system conditions are auctioned. These represent the interior dimension of any nomogram.

5) **Which set of simultaneously feasible rights is chosen? There are a great many combinations.**

   See the response to Question 4. Generally, the RTO would offer PTRs conservatively in the initial auction, and release additional capacity seasonally.

(See last 3 slides in N. Rao's presentation of the zonal approach in Dallas, TX, 6/19/00, posted on the SPP website). Additional capacity rights could be made available by the RTO closer to real time as operating conditions permit.

6) **Will native load receive an allocation of these PTRs? If so, how. If not, how do they mitigate their substantial increase in cost?**

This is a question for stakeholders and SPP, and is independent of the type of CM scheme adopted. Existing contracts could be awarded PTRs.

If native load, apart from contracts, is not granted PTRs, revenues from PTR auctions would be credited to transmission owners' revenue requirements (to prevent "and" pricing), thereby reducing the access fees paid by native load.

The level of cost increase resulting from congestion management will depend on the extent to which native load relies on congested flowgates. Accordingly, if a given utility's native load is served without use of congested flowgates, there would be no increase in costs.

7) **How are counterflow schedules or rights accounted for when the system capability is calculated?**

Capabilities can be defined without requiring any assumptions of counter flows, much the same way transfer capabilities are determined today.

8) **How are the initial flowgates determined?**

This is a critical design issue, and requires significant stakeholder participation. However, certain analysis has to precede this judgement. The expected monetary value of congestion associated with specific flowgates needs to be quantified. This requires an assessment of the frequency of congestion and the associated cost of congestion. A robust selection will require some assessment of the impact of retail choice, and reasonably conservative criteria.

9) **How many source/sink pairs are modeled? Is it bus to bus, zone to zone, etc.**

It is not clear what this question is referring to. The objective is to model expected flow patterns using currently available transmission modeling software. These software systems are based on nodal injections and withdrawals.

10) **If a flowgate is added, how are the other flowgate ratings adjusted so that the set remains simultaneously feasible? How are losers of rights compensated?**

It is anticipated that auctions of PTRs would occur on a systematic schedule such as annually. Under these circumstances new – commercially significant -- flowgates would be added (or subtracted) from the set at the time of each primary auction. As a result there would be no commercial impact on existing rights since there would be none in force. All distribution factors would be recalculated prior to the primary auction.

11) If the answers to 8) and 9) are as many as necessary to catch all limiting elements for all possible transactions, how is that different than an LMP system in terms of complexity and functionality?

If a system ends up requiring the definition of an unmanageably (as judged by stakeholders) large set of flowgates, then transacting could get complex. However, the complexity of transacting (requiring rights on several flowgates for a single transaction) can easily be handled by software (e.g., APX) and shielded from market participants. Further, note that under an LMP system there are <u>*thousands*</u> *of point-to-point combinations in a network as large as SPP. This granularity creates significant price risk (and reduced liquidity), even if most combinations have uniform prices. With the dynamic nature of trading required under retail choice, such complexity would stymie market activity. NERC has 60 flowgates defined for SPP. A lot of these are administrative, and would probably not be commercially significant. Thus, even in the worst case (60 flowgates), the level of complexity is not comparable to a nodal LMP system.*

12) Why is it more desirable to trade PTRs, if various PTRs are needed based on source/sink pairs, than it is just to trade energy the source and the sink?

See Answer 11. There would also be several source/sink pairs for which no PTRs would be required, and for which no transmission risk has to be born by market participants. In a nodal system where it may be argued that the same source/sink pair would have uniform prices, there is always the risk that transitory transmission problems would cause sudden price differences. This risk is unnecessary and commercially a hindrance to trade, especially when the transmission provider/operator may be responsible for such problems.

13) How does bidding for non-firm flowgate rights give the market price certainty for a contemplated transaction? What system will be used to clear these transmission auctions in real time.

The value of non-firm rights will always be capped by the price of firm rights, which will be established in the liquid bilateral market. Purchasers of non-firm clearly will have a higher risk-adjusted expectation of price/value, but choose to bear this.

No transmission rights will be auctioned in real time. Beyond initial auctions, rights will trade and clear continuously in secondary markets.

14) Does a flowgate model, if not nodal or small zonal, facilitate retail competition.

See Answer 5 in TCA's Q/A on Congestion Management.

15) How does a real time balancing market interact with a flowgate system? How could bidders for energy into the market be required to make sure transmission is available for their dispatch.

The scheduling time frame forms the intersection of the forward flowgate-based markets and the real-time dispatch. The real-time balancing market will serve as 'clean-up' for imbalances in the forward market (as scheduled when the market closes) due to unforeseen changes in supply and demand. The structure of the real-time market (level of *centralization in dispatch, method of price setting at a zonal or nodal level) is independent of the flowgate approach.*

Generators will have to purchase transmission rights as necessary depending on where they sell their power. All generators should have schedules corresponding to their desired dispatch. In real-time, dispatch may deviate from their schedules due to emergency-type conditions, in which case they need to settle the discrepancy in the balancing market depending on their net position.

16) What would an initial allocation of PTRs look like for the present makeup of the SPP?

No analysis of this has yet been undertaken.

17) How can a party that constructs a transmission facility receive compensation for removing congestion?

One alternative is to award them rights (PTRs) equivalent to the capacity they make available. This issue must be dealt with in any congestion management systems.

Questions about Nodal LMP:

18) How is market power within a congested area mitigated?

Market power is fundamentally independent of the CM system used. Market power has to be mitigated by other means, pursuant to FERC rules.

19) How will initial Financial Transmission Rights (FTRs) be allocated. Is there a guarantee that a set of simultaneously feasible FTRs that protects native load will exist initially?

See Answer 3. Initial allocation of FTRs is not dependent on the CM scheme. See Answer 6 for native load considerations.

20) What would an initial allocation of FTRs look like for the present makeup of the SPP?

We haven't conducted such an analysis.

21) Does the balancing market have to be run by the RTO or could another party clear the bids.

The balancing market is not functionally different from the forward settlement markets, since the same security-constrained dispatch and Optimal Power Flow (OPF) is run in all markets, which includes bids and system state parameters. The entity operating the system has to perform this function, since they are closest to the physical system and its real-time state. The RTO is therefore the only option to operate the markets in the nodal approach.

22) Can people other than generators bid energy? Can energy be bid into the system at points other than generator buses? Can the system clear straight financial transactions allowing for other entities to market FTRs?

In some nodal systems, loads can bid as well, and submit bids at load buses. The RTO has to be involved in the auction of FTRs. The secondary market for FTRs need not be run by the RTO.

23) How can a party that constructs a transmission facility receive compensation for removing congestion? If payment is in FTRs then it seems the builder would get paid with something that they just made worthless.

Payment in FTRs is typically the method of compensation. The approach relies on the fact that new investment, though alleviating congestion, would capture some of the congestion rent, due to its lumpiness. Significant generation investments and announcements in high-priced areas on the grid the Northeast and California following the implementation of locational pricing appear to vindicate this conjecture.

<u>ATTACHMENT No. 6</u>

<u>Questions about Congestion Management</u>

In the Southwest Power Pool
Responses by Tabors Caramanis & Associates

1. What is the cost of congestion management in SPP and Entergy today?
   - How many MWhs of transactions are curtailed each year?
   - How many transactions did not occur due to the presence of congestion?
   - How much has redispatch cost SPP and Entergy in the past year?

[SPP Staff to Answer?]

2. How centralized would dispatch in the SPP have to be to implement a zonal scheme? How much centralization is needed to implement a nodal approach?

– How much would it cost to consolidate 17 control areas into one?

The nodal approach requires a much greater level of central control than the zonal/flowgate approaches. All existing nodal systems operate in single control area environments.

The zonal/flowgate approach lends itself to a hierarchical form of information flow and of control. Therefore, zonal/flowgate approaches can be implemented with dispatch at the zone-level. This has the advantage of allowing the use of the information needed for system operations at different levels within the control hierarchy.

<u>Decentralization under Zonal/Flowgate</u>

The preservation of zone-level dispatch will require the continuation of coordination mechanisms between control areas to manage rare discrepancies across zones, such as minimizing Area Control Errors (ACE), and managing unusual circumstances where inter-zonal flowgates are constrained in real-time. The latter is likely to be a rare occurrence, since inter-zonal congestion is self-managed, and therefore absent, right up until real-time (hour-ahead).

There are several ways to handle this coordination. Some of these methods are in fact similar to the proposed coordination between dispatchers proposed by Baldick and Hogan (see <u>Decentralization Under Nodal</u>). The difference is that since in all forward markets schedules are balanced and congestion is self-managed, only under these rare circumstances does dispatch across control areas need to be coordinated. A good analogy is what the Florida Power Broker model has had in effect for the past 15 years. They chose to put in an inc and dec system with bidding ahead of the hour. This system has worked really well and was shown to get all of the meaningful dollars out of the system. Thus, the advantage of centralized dispatch in handling these unusual circumstances are mostly likely outweighed by the cost of increasing the bureaucratic functions and consolidating as many as 17 control areas.

Decentralized Under Nodal

The nodal approach is much harder to implement with decentralized dispatch, since the RTO "accepts all schedules" and has heretofore never been proposed for any RTO. The theory of multi-control area ISO coordination and distributed optimal power flow have been addressed recently.[1] Very simply put, ISOs share dispatch results and resolve inter-area congestion through adjustment bids. Issues of concern are the convergence of an efficient outcome across multiple areas based on adjustment bids, and the implementation feasibility and success. New York and NEPOOL, as well as Ontario and New York deal with this issue (although neither NEPOOL nor Ontario is presently a nodal system), and they have MOUs to handle price discrepancies. However, this issue has not been resolved or adequately addressed.

For all practical purposes, such an approach would be risky, in the least, and an experiment in a 17 control area environment such as SPP.

See Question 3 below for costs.

3. How much will a transition to a nodal, zonal, or flow-based congestion management scheme cost?
- How much training, cost and adjustment would be required to transition to the bid-based, centralized pool necessary for a nodal system?
- How much training and investment would be required to develop and operate independent exchanges for energy, ancillary services, and transmission rights?

Estimating transition costs requires significant analysis and discussion. The following is a breakdown of cost categories and the applicability to nodal and zonal/ flowgate schemes to facilitate a discussion of costs.[2]

The costs of creating the ISOs in the northeast (in the referenced document in Footnote 2) are drastically understated and therefore misleading, since the pooling ISO institutional structures and significantly the SCADA type functions and software were developed over several decades at considerable expense, which are not included in the estimates shown. The CA ISO is the only example of a 'greenfield' ISO. The currently proposed RTOs in ERCOT, Desert Star and Mountain West ISA will provide good examples of RTO centralization costs under zonal/flowgate schemes.

Generally, with a zonal/flowgate system and decentralized dispatch, the operating administrative costs for the RTO will be significantly lower. The up front capital costs will also likely be less, although this will depend on the number of flowgate/zones necessary, their coincidence with current control area boundaries, and the ability to learn from the experience of California and other proposals the development of exchanges for energy, transmission and ancillary services.

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[1] Balho H. Kim and Ross Baldick, "Coarse-Grained Distributed Optimal Power Flow," IEEE Transactions on Power Systems, Vol. 12, No. 2, May 1997, p. 937, Coordinating Congestion Relief Across Multiple Regions, M. Cadwalader, W. Hogan, et al., Oct. 1999.

[2] See the Ontario Independent Market Operator (IMO) fee submission, which describes the costs of 4 ISOs in the US (CA ISO, NEPOOL, NYISO and PJM). http://www.iemo.com/imoweb/mkt_trans/mkt_definition/rules/ElectricityMarket/Fees/FeeDesign.pdf, Exhibit E1, Tab 1, Schedule 1, Appendix 2.

Cost Category	***Zonal/ Flowgate***	***Nodal***
Capital (Outlay) Costs		
Software systems development*	Lower	Higher
Administrative structure (staff, facilities, equipment, etc.)	Lower	Higher
Market exchanges	Higher	Lower
Training and consulting		
Operations Cost		
Compensation, benefits, consulting services,	Lower	Higher
Facility costs (leases)		
Misc. expenses		
Indirect Costs		
Market management (exchanges)	Higher	Lower
Market participant training*	Lower	Higher
Unquantifiable costs of market inefficiency*	Lower	Higher

*Areas where significant cost differences are expected between nodal and zonal

4. How will the bilateral markets be affected by a change in the congestion management system?

– Could we retain our present bilateral-based transaction structure in a zonal scheme? Could we in a nodal scheme?

A. *Under a zonal or flowgate pricing scheme, bilateral trade is expected to be the dominant form of transaction. The simplicity of physical rights and the absence of a 'middle-man' in the energy, transmission and ancillary service forward markets ease bilateral trade. Market participants should not face much of a learning curve in the transition to a zonal or flowgate system. Most of the adjustment would lie in trading and managing capacity rights.*

Under a nodal system, a steep learning curve is likely for market players just to participate in energy markets. For example, they have to learn how to incorporate their complex cost functions into bids. In addition, as the market is tested and developed, participants would have to learn the new complex system of transmission rights for all combinations of withdrawals and injections. Liquidity in bilateral trading may dry up due to the need to bid into a central energy market and manage a complex system of transmission rights.

5. How will retail competition impact our decision criteria for congestion management?

Two important developments brought by retail competition will impact the decision criteria for selecting a congestion management scheme: a) The creation of a new set of market players, retail aggregators, who will face little understood (poorly metered) and constantly varying load profiles; b) Increase in the volume of and pattern of trading, particularly across control areas and in and out of the RTO.

The former consideration will increase the value of price certainty and simplicity of trading. ***The value of simplicity when moving from wholesale competition to retail competition cannot be over-emphasized. Complexity will impede retail development.*** *Retail aggregators will likely have dynamic* *portfolios (supply and demand) that can change on a daily basis. Needing to purchase a different transmission right for every single contract/transaction in a market that is not particularly liquid (e.g., point-to-point FTRs in a nodal system) would hinder trade. To work well, retail access requires a liquid point into and out of which players can balance their energy requirements. This requires a well functioning balancing pool. To make this work with a nodal system you need DISTINCT locations where the balancing market can clear. This is an advantage of the zonal approach because each of the zones becomes the site of a balancing market.*

In such circumstances, liquidity and price certainty in forward markets for energy and transmission capacity are vital. The physical rights approach and ex-ante price characteristics of the zonal/flowgate approaches will be more likely to provide both these characteristics. This scheme can be likened to the gas industry, where pipeline rights are traded in a similar manner. The latter consideration of changes and increases in flow patterns influence implementation detail rather than decision criteria for selecting a zonal/flowgate scheme. This will require careful analysis, and possibly a conservative selection, of flowgates to ensure reasonably robust zone definition, and a closer look at flowgates on the seams, in determining determine "commercially significant" constraints.

6. Could a nodal approach co-exist within a zonal scheme in different parts of the same RTO?

   Such co-existence has never been thoroughly researched or discussed in academic literature.

   With a flowgate-model, nodal could strictly speaking co-exist with zonal. Here you would have a decentralized forward market for all transmission rights with physical rights, but have a primarily nodal balancing calculator in real-time, and aggregate certain regions into zones/hubs. However, to operate certain regions with a full set of nodal rules (i.e., ex-post pricing, and unbalanced schedules) and others with zonal/flowgate rules within an RTO would be tantamount to creating new seams within an RTO, which is messy. This would partly defeat the purpose of integration under a common, simple commercial model, and likely result in 'isolation' of that control area from the remaining RTO in terms of trading. This outcome is likely the case if the region for a nodal scheme is selected not on the basis of grid characteristics, but for other institutional/political reasons.

7. Could curtailments occur regardless of the existence of any congestion management system? Are they more likely to occur under one congestion management approach or another?

   All the approaches would introduce market-based mechanisms for resolving forecasted congestion, and minimize the curtailment-based method of TLR procedures. The only expectation of curtailments under all approaches is under unexpected, real-time emergencies, such as line outages due to storms. In such situations, if the capacity of any loaded intertie were reduced beyond the ability of the market to clear congestion, curtailment would be required. Such curtailment would not differ under any of the congestion management schemes.

8. To what extent does each method provide price certainty? To what extent is price certainty only available through entering into a financial hedge?

   The zonal/flowgate approach provides a much greater degree of price certainty than the nodal approach.

   Under the nodal approach, generators bid into a central energy market. Using computer models, the RTO determines the price of power at each node, and assigns congestion charges on the basis of cost differentials between sources and sinks. The assumption is that all power is bought and sold in the spot market. Congestion charges are not known until after a transaction is completed (ex-post pricing). That means that a seller of power may find out after the fact, that a sale they made was uneconomic. This uncertainty represents a risk that prevents many potential deals from being done. In contrast, under the zonal and flowgate approaches, transmission customers purchase transportation rights at market prices *that are independent of the then current cost of energy. This model is similar to the purchase of firm capacity on natural gas pipelines. A seller of electricity knows in advance (ex-ante) what the cost of moving power across a congested interface, and then can make a rational decision as to whether or not to proceed with a transaction.*

Price certainty in forward markets derives from high liquidity. In the absence of a liquid market, traders have to rely on their own estimates of future expected congestion or energy prices, but with liquid trading, the market 'internalizes' these estimates and arrives at a better answer than individual traders. As discussed in Question 5 above, the ex-ante, continuously clearing bilateral markets for energy and transmission capacity in the zonal/flowgate approaches will provide price certainty to traders. In the nodal approach, a perfectly liquid forward market for FTRs would also provide the same price certainty, but such liquidity is unlikely, given the complexity and non-standardization of product definition (thousands of point-to-point combinations, each with limited trading).

9. What measuring points do we have available now? What is currently available from metering already installed?

[SPP Staff to Answer]

10. Where on the SPP system can we expect to have TLRs?

[SPP Staff to Answer]

11. Is it possible to design a system that can be scaled in accordance with the magnitude of the problem on the SPP system?

Yes. We do not believe that the implementation of a full-blown nodal system is needed to manage the level of congestion being experienced in the SPP and Entergy regions today. A well thought-out zonal or flowgate approach will meet the needs for effective and equitable congestion management more quickly and less expensively. They are much better adopted to “scaling’. The 'scaling process' is essentially defining the number of significant flowgates, and the number of zones. Further, the real-time dispatch functions would also scale to the extent that an RTO with very few zones would not need to be designed early on to perform centralized dispatch, but could be centralized at a later point if the system does develop unforeseen complexities (e.g., several new zones).

The nodal approach, on the other hand, is a one-time, irreversible, one-size-fits-all process that may be 'over-kill'.

12. How will the devised congestion management system operate with respect to current transmission contracts that do not provide for application of a congestion charge?

Congestion charges are charged and assessed separately and independent of existing contract terms and conditions. Typically, an existing contract that commits service over a defined 'commercially significant' flowgate would receive firm rights on that flowgate. In the event of emergency circumstances where firm rights cannot be met, they would pay for congestion separately from their contract based on the price difference across the flowgate. The method of assessment would depend on the implementation of real-time congestion management, but would typically be through supplemental energy bids. If a contract is not awarded a firm right for some reason, this right can be purchased in an auction or secondary market.

13. Can LMP work in a multi-control area environment? If so, how?

See Response to Question 2.

14. What CM system provides the lowest cost to load?

The costs need to be addressed individually. First, from the perspective of the administrative costs of instituting and running the market, the zonal/flowgate schemes are most likely to have lower costs, due to the minimal bureaucracy envisioned for the RTO, the incremental requirements for retraining, and less complex systems development (See Question 3). The costs borne by utilities in re-training to adapt to bid-based pools (necessary in the nodal approach) will ultimately filter down to loads. Also, the simpler the scheme instituted, the less likely the potential for lengthy 'gestation periods' in implementation.

The other measure of the cost to load is the efficiency of the CM scheme in resolving congestion and thereby minimizing the total energy costs. This is a non-trivial question, since there are indirect costs associated with market inefficiencies that may not be reflected specifically in congestion costs. From the perspective of resolving congestion, the nodal approach has a higher granularity of price discovery. However, because zones should be defined such that intra-zonal congestion is minimal, this additional granularity does not provide any benefit. In the event that significant unforeseen congestion develops on paths other than the selected commercially significant paths, new zones/flowgates would be defined. Thus, neither scheme has a fundamental advantage in minimizing congestion costs.

The costs associated with poor liquidity in bilateral markets, and with the risk of software problems and market functioning improperly (such as in New York) can be quite significant, though difficult to quantify. Poorly functioning markets will stifle innovation, have little competitive pressures to reduce costs and drive energy prices down, and therefore not achieve the fundamental objectives of wholesale competition.[3]

Finally, the unquantifiable inequity of nodal pricing needs to be considered. That is, the benefit and fairness of attributing costs to consumers that are caused by operator judgement, lack of investments by the ISO, or quirks in the transmission system, are questionable.

Thus, overall, the zonal/flowgate approach will likely cost less to implement, and the benefits in overall market outcomes from liquidity and competition are likely to be far more significant.

15. Which of the system types can we implement within the time frame we have? What time frame is required to implement each of the various CM system options, given the nature and current configuration of SPP infrastructures and institutions? Time, as well as cost, is a constraint on our selection of a CM system.

The nodal system is virtually unimplementable in SPP's time frame, given the experience of other ISOs. To get something going you need to work with what you have. For SPP this is the flowgate approach, since the information is available, the operators understand it and it can be laid on top of the existing control area functions.

16. What system analysis tools are available to assist us with an analysis of the entire SPP system?

Such tools are available. For example, TCA has modeled and simulated the SPP system as part of the Eastern Interconnection using GE MAPS (Multi-Area Portfolio Strategy), which is security-constrained, least-cost dispatch model, with full generation and transmission representation. This can be used to determine congestion patterns and congestion costs. TCA also has a statistical package, SAS, which we have used to perform clustering analysis to identify zone boundaries.

17. What obligation (s) must generators accept in order to have an effective CM system?

In the zonal/flowgate approach in the forward market, generators will have no obligation vis-à-vis the RTO. They can independently arrange bilateral contracts in the energy exchange, secure necessary transmission rights across zones in the transmission exchange, and purchase necessary ancillary service requirements in the ancillary service exchange.

In order to allow the dispatcher to manage balancing in the zonal/flowgate approach, generators need to submit to the control area inc and dec bids for supplemental energy. Generators

[3] Notably, the United Kingdom, one of the most mature electricity markets in the world, has abandoned the centralized pool approach due to limited market development.

have the obligation to generate if their bids are selected. Alternatively, the control areas and the RTO could substitute inc and dec bids with call contracts for generation. Generators would then sell a portion of their energy in the form of these call contracts, and have the obligation to generate when called for dispatch.

18. Is there a migration path from one methodology to another? For example, can we move from zonal to nodal or vice versa, in the future?

    Theoretically, one could migrate from either approach to the other; however, it would make more sense to start with a simpler, less expensive zonal/flowgate approach and then implement the more complex and data-intensive nodal approach if warranted. The only infrastructure that may not be carried over fully from a zonal/flowgate approach into a nodal approach are the separate exchanges instituted for bilateral trade in energy, transmission and ancillary services. However, the energy exchange may only need to be subsumed into the ISO, since the functions and administrative machinery would need to exist.

    On the other hand, much of the physical and operational infrastructure and training that is needed to implement a nodal approach, including optimal power flow models, will be unusable if SPP later elects to implement a zonal/flowgate approach.

ATTACHMENT No. 7

Transmission Market versus Locational Energy Market

The transmission market is primarily based upon trading of Physical Transmission Rights (PTRs). The locational energy market can support both physical and Financial Transmission Rights (FTRs). A basic premise of the transmission market is that a robust transmission market can prevent congestion and provide a market mechanism to value these rights.

Although the robust market necessary to support the PTRs is a goal, we do not feel that the infrastructure and market can be present immediately, but will develop over time as congestion management tools are made accessible to the market participants. There are questions about how "firm" these PTRs could be from the available data. There are also problems in the limitations of the present pro-forma tariff that would not create a lucrative market in PTRs.

Seams issues between the employment of different methodologies are not well defined or understood and significant tariff changes may need to be implemented as the seams issues are understood.

Nodal versus Zonal

Nodal pricing allows differentiation between source and sink by bus location. In a nodal method each load can make bilateral arrangements with any generator and pay the cost of transmission congestion from the generator bus to the load bus. A nodal concept requires that load and resources be identified to each node (either by direct identification or through allocation). A nodal methodology can be implemented by assuming a distribution of the scheduled and aggregated (actual) load based on historical substation metering data.

Zonal pricing blends the bus prices within the zone and presents a single zonal price. A zonal concept identifies load and resources to a zone. It is important that the zone is properly identified to place congestion points between zones. These zones have to be predefined and data aggregation support identification of load to these zones. The zones may be re-identified based on changes in congestion to maintain commercially significant congestion on the zonal boundaries.

The nodal methodology allows more precision in assignment of congestion costs to load. The zonal methodology obtains inter-zonal precision by defining zones to place congestion on zonal boundaries. This may be difficult because the current flowgates overlap in some cases, as shown in the attached excerpt.

SPP Recommendation

The staff recommends the use of nodal pricing for resources and zonal pricing for "load" busses. The nodal prices for resources would be obtained from the bids submitted for Energy Imbalance Service (EIS) in the spot balancing market. The "load" bus for a zone would be calculated using an assumed distribution of all load within the zone to busses and calculating a weighted average price for the zone.

Using a nodal resource price and zonal load price will allow some differentiation among the load for intra-zonal transactions based on the resource bus price differences.
Financial Transmission Rights (FTRs) will be used rather than Physical Transmission Rights (PTRs) in order to allow a more fungible right in the opening market.

In conjunction with the FERC order on NEPOOL stating that transmission customers must have the ability to limit the congestion charge they are willing to pay, we believe that each transmission customer who wishes to limit their congestion charge will have to demonstrate through actual measured load, the ability to control the load. The reaction to command to reduce load must be measurable.

An example of the implementation of the nodal/zonal methodology with FTRs follows:

Generator Data

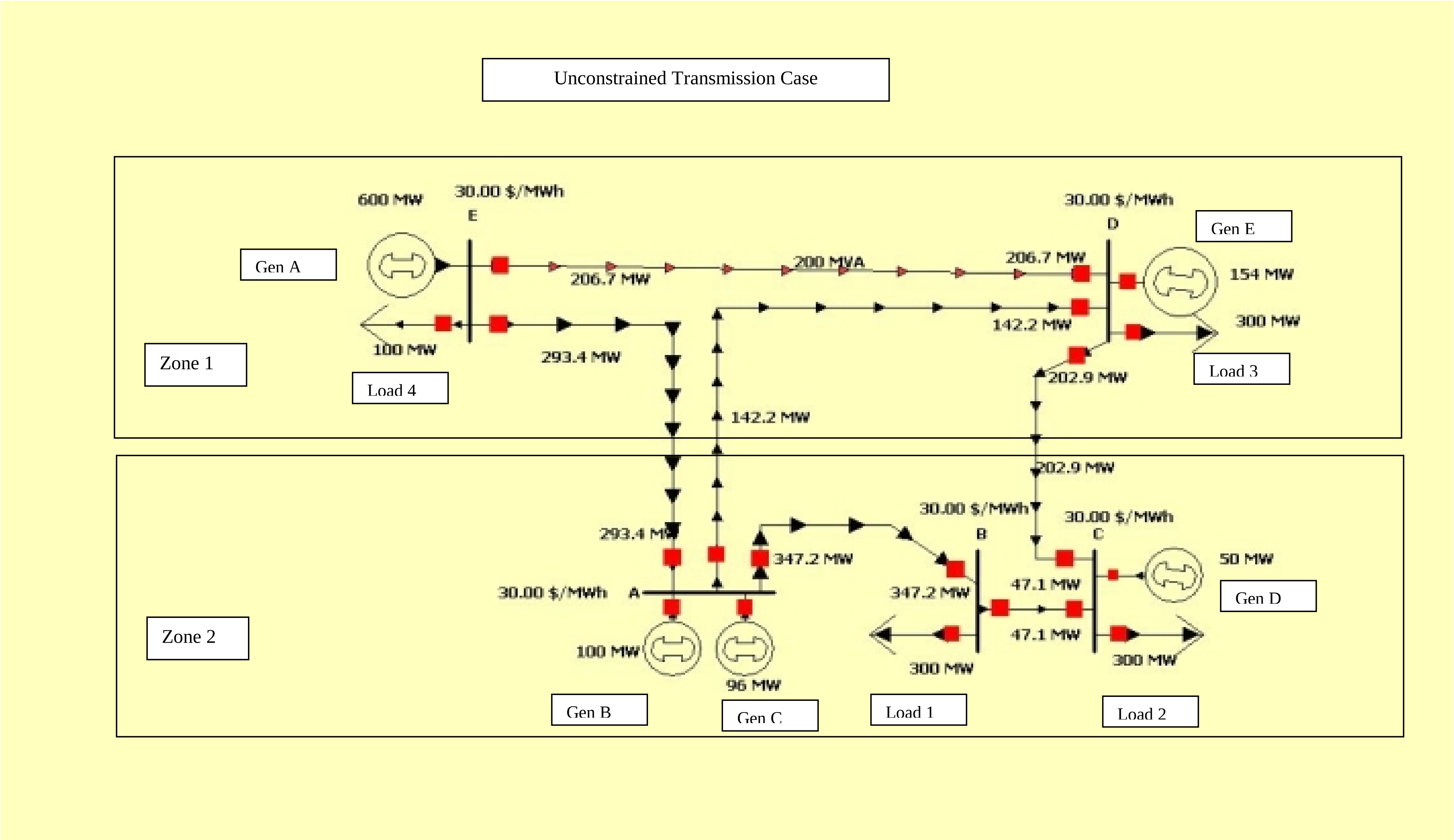
Generator	Bus	Max MW	Scheduled MW
A	E	600	600
B	A	110	100
C	A	100	96
D	C	520	77
E	D	200	127

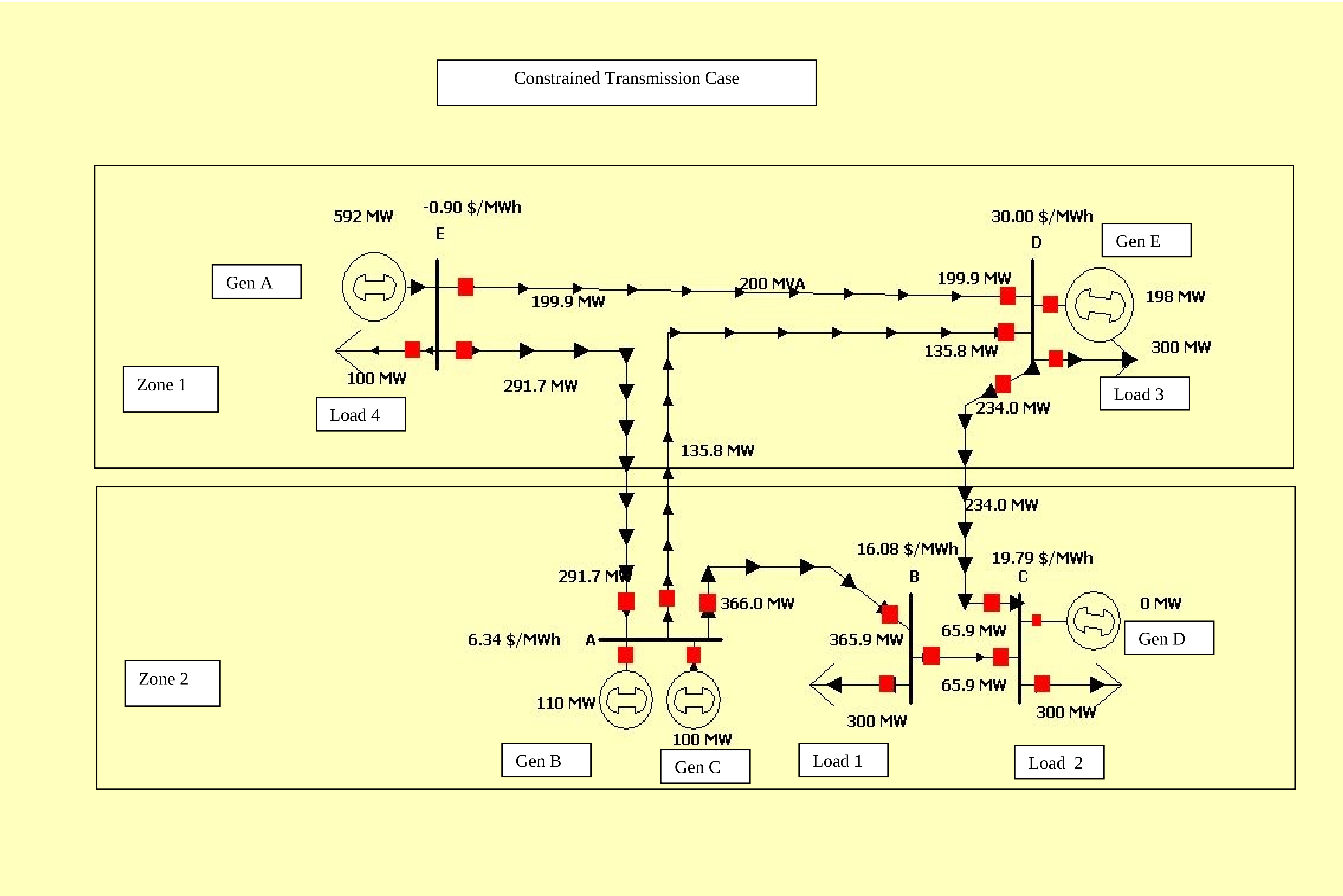
Bilateral Schedules

Load	MW	Generator
1	100	A
	73	C
	50	D
	77	E
2	100	A
	100	B
	23	C
	77	E
3	300	A
4	100	A

Ancillary Services

Resource	Inc MW	Inc Bid	Dec MW	Dec Bid
Gen A		10	600	1
Gen B	10	14	100	2
Gen C	4	15	96	2
Gen D	470	30	50	4
Gen E	46	30	154	4




Constrained Transmission Case
Zone 1
Gen A
592 MW
-0.90 $/MWh
E
199.9 MW
200 MVA
199.9 MW
30.00 $/MWh
D
Gen E
198 MW
300 MW
Load 3
135.8 MW
234.0 MW
100 MW
Load 4
291.7 MW
135.8 MW
Zone 2
234.0 MW
16.08 $/MWh
19.79 $/MWh
B
C
291.7 MW
366.0 MW
6.34 $/MWh
A
365.9 MW
65.9 MW
0 MW
Gen D
65.9 MW
110 MW
100 MW
300 MW
300 MW
Gen B
Gen C
Load 1
Load 2

Zonal Pricing (Load Bus)

Congested Case

Zone 1 =((Load 3*Bus D price)+(Load 4*Bus E price))/(Load 3 + Load 4)
Zone 1 = $22.275

Zone 2 =((Load 1*Bus B price)+(Load 2*Bus C price))/(Load 1 + Load 2)
Zone 1 = $17.935

Node Price (Source Bus)

Congested Case

Gen A	-$0.900
Gen B	$6.340
Gen C	$6.340
Gen D	$19.790
Gen E	$30.000

Congestion Charges

Load	Source	MW	Price Delta*	Charges
1	A	100	$18.835	
	C	73	$11.595	
	D	50	($1.855)	
	E	77	($12.065)	$1,708.18
2	A	100	$18.835	
	B	100	$11.595	
	C	23	$11.595	
	E	77	($12.065)	$2,380.68
3	A	300	$23.175	$6,952.50
4	A	100	$23.175	$2,317.50
				$13,358.86

* Price Delta is between Zonal Price and Source Bus

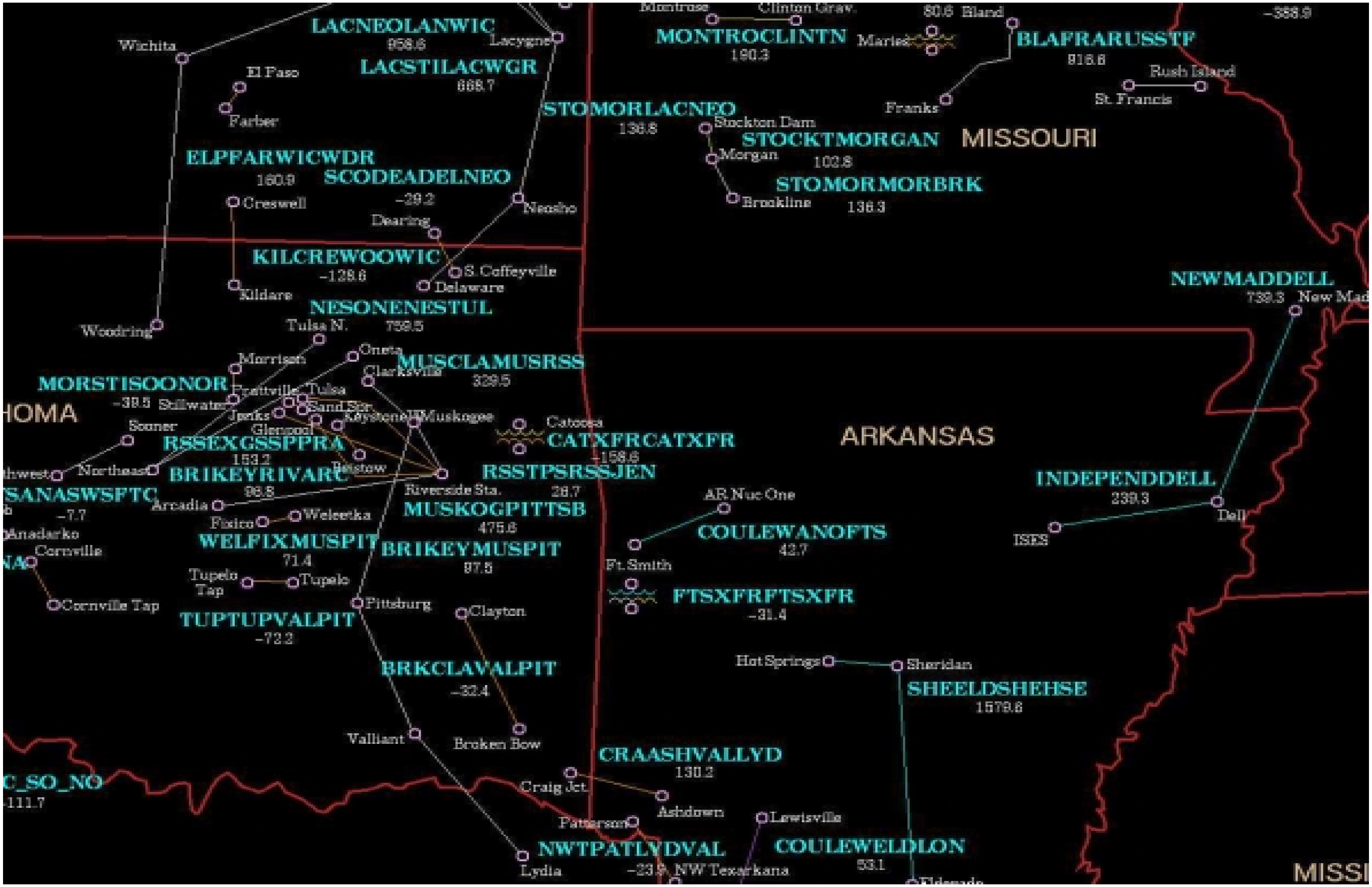
Net Available for FTRs

Congestion Charges		$13,358.86
(Inc)/Dec Impacts		
Gen A	8 x $1	$8.00
Gen B	10 x $14	($140.00)
Gen C	4 x $15	($60.00)
Gen D	50 x 4	$200.00
Gen E	44 x 30	($1,320.00)
Net (Inc)/Dec		($1,312.00)
Net Avail for FTRs		$12,046.86

If FTR shared zonally on inverse pric

Zone 1 = 1 - 22.275/(22.275+17.935)
Zone 1 = 44.60%
Zone 2 = 55.40%

	Congestion	
	Charges	FTRs
Load 1	$1,708	$2,788
Load 2	$2,381	$3,886
Load 3	$6,953	$4,030
Load 4	$2,318	$1,343
	$13,359	$12,047



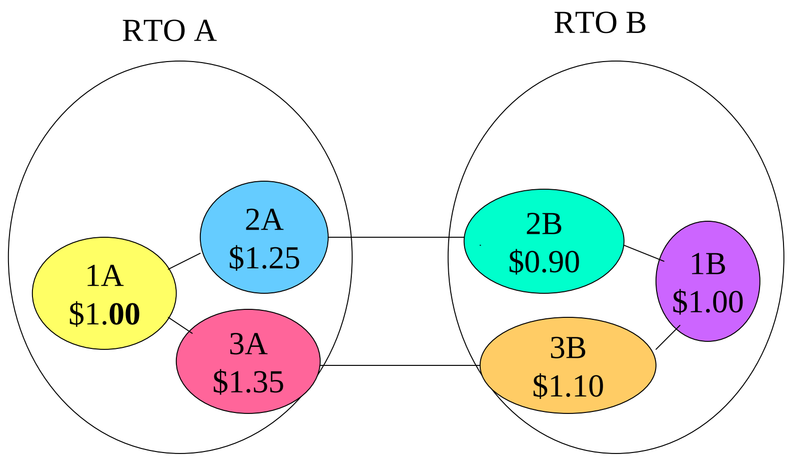
LACNEOLANWIC
958.6
LACSTILACWGR
668.7
STOMORLACNEO
136.8
MONTROCLINTN
190.3
BLAFRARUSSTF
816.6
-388.9
STOCKTMORGAN
102.8
MISSOURI
STOMOR MORBRK
136.3
ELPFARWICWDR
160.9
SCODEADELNEO
-29.2
KILCREWOOWIC
-128.6
NESONENESTUL
759.5
NEWMADDELL
739.3
MUSCLAMUSRSS
329.5
MORSTISOONOR
-39.5
HOMA
RSSEXGSSPPRA
153.2
BRIKEYRIVARC
96.8
CATXFRCATXFR
-158.6
RSSTPSRSSJEN
26.7
ARKANSAS
INDEPENDDELL
239.3
SANASWSFTC
-7.7
MUSKOGPITTSB
475.6
COULEWANOFTS
42.7
WELFIXMUSPIT
71.4
BRIKEYMUSPIT
97.5
FTSXFRFTSXFR
-31.4
TUPTUPVALPIT
-72.2
BRKCLAVALPIT
-32.4
SHEELDSHEHSE
1579.6
CRAASHVALLYD
130.2
C_SO_NO
-111.7
NWTPATLYDVAL
-23.9
COULEWELDLON
53.1
MISS
Wichita
El Paso
Farber
Lacygne
Montrose
Clinton Grav.
80.6
Bland
Maries
Franks
Rush Island
St. Francis
Stockton Dam
Morgan
Brookline
Creswell
Neosho
Dearing
S. Coffeyville
Delaware
Kildare
Woodring
Tulsa N.
Oneta
Morrison
Clarksville
Prattville
Tulsa
Stillwater
Sand Spr.
Jenks
Keystone
Muskogee
Sooner
Glenpool
Catoosa
Northeast
Barstow
Riverside Sta.
Arcadia
Fixico
Weleetka
AR Nuc One
Anadarko
Cornville
Ft. Smith
New Mad
Dell
ISES
Tupelo Tap
Tupelo
Pittsburg
Clayton
Cornville Tap
Hot Springs
Sheridan
Valliant
Broken Bow
Craig Jct.
Ashdown
Patterson
Lewisville
Lydia
NW Texarkana
Eldorado

EXAMPLES OF TRANSMISSION TARIFF PRICING WITH RTO RECIPROCITY

Report to the SPP RTO Working Group
By the RTOWG Seams Sub-Team
July 12, 2000

1

RTO Configuration for Transmission Tariff Reciprocity Examples Between Adjacent RTO's



1A, 2A & 3A represent zones with zonal pricing

1B, 2B, 3B represent zones with zonal pricing

2

RTO Transmission Tariff Pricing

- RTO A: "Out Charge" is the lowest cost zone rate connected with the external control area designated as the POD = $1.25
- RTO B: "In Charge" is the zone rate where the load is located = $1.00

❖ W/O rate reciprocity, transmission customer pays the sum of the 2 charges = $2.25

3

Two Reciprocity Alternatives Are Being Considered

- Alternative 1: The customer pays 1/2 the source RTO rate and 1/2 the sink RTO rate. Each RTO collects it's respective revenue and asses a surcharge to cover the remaining shortfall.
- Alternative 2: The customer pays the sink RTO rate. The revenue is allocated to both RTO's on a flow based method.

4

Alternative 1: Half Tariff Rates & Surcharge Shared Between Both RTO's (Two RTO's 1A to 1B)

- RTO A waives ½ out charge of $1.25 (= $0.625).
- RTO B waives ½ sink zone 1B rate of $1.00 (= $0.5).
- RTO's assess surcharges to cover their respective revenue shortfalls.

a) ***With reciprocity customer pays $1.125= ($0.625 + $0.50).***

b) ***RTO A collects surcharge of $0.625 and RTO B collects surcharge of $ 0.50. Each RTO determines how its surcharge is to be collected.***

d) ***The Surcharges to cover revenue shortfall are allocated back to Transmission Owners within each RTO based on their tariffs.***

5

Alternative 2: Sink Zone Rate & Flow Based Revenue Allocation Shared by RTO's (Two RTO's 1A to 1B)

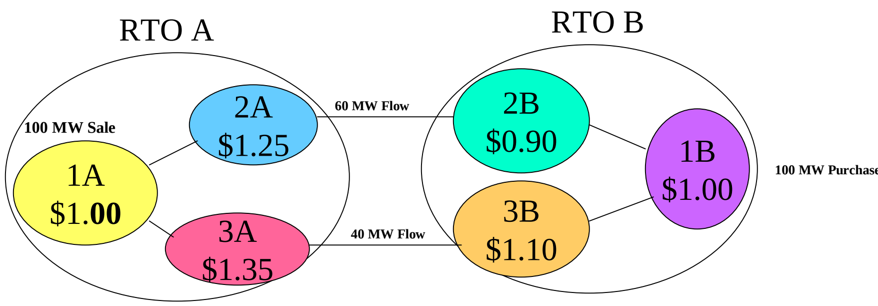
- RTO A waives out charge of $1.25
- Customer pays sink zone 1B rate of $1.00
- RTO's assess surcharges to cover their respective revenue shortfalls.

a) ***With reciprocity customer pays $1.00***

b) ***Revenue of $1.00 is allocated among RTO A and RTO B based on flow. Revenue distributions for all transactions will tend to cover the revenue shortfall.***

6

Example of Flow Based Revenue Allocation for Reciprocity Between Two RTO's



Transaction from 1A to 1B of 100MW

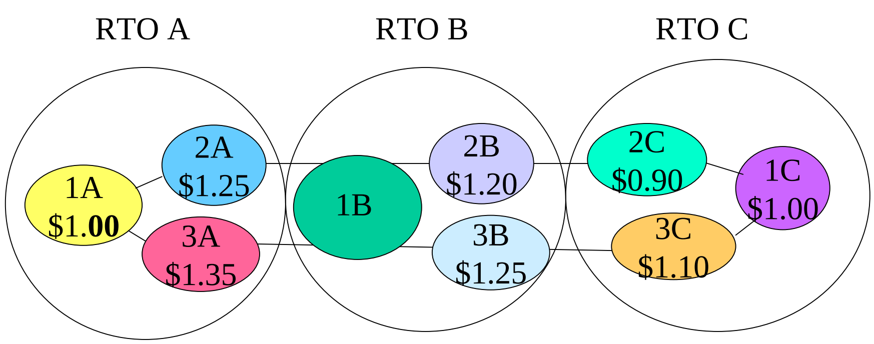
Zone 1B rate= $1.00 /kw-mo

Zone	Transaction MWMiles	% MWMile	Rev. Rate allocation to RTO's	Monthly $ (Allocation * MWMile)	
1A	12,300	19%			
2A	10,440	16%	$0.50	$50,107,13	RTO A
3A	10,000	15%			
1B	8,800	13%			
2B	10,800	17%	$0.50	$49,892,87	RTO B
3B	13,000	20%			
Total	65,340	100%	$ 1.00	$ 100,000.00	

1. Customer pays the 1B zone rate of a $1.00/KW-MO
2. With reciprocity, the revenue is allocated to each RTO based on zonal flows as per example above
3. RTO A would collect the dollars for 1A through 3A and RTO B would collect for 1B through 3B

7

RTO Configuration for Transmission Tariff Reciprocity Examples Between Non-Adjacent RTO's



Transaction from 1A in RTO A through RTO B to 1C in RTO C

8

RTO Transmission Tariff Pricing Between Non-Adjacent RTO's

- RTO A: "Out Charge" is the lowest cost zone rate connected with the external control area designated as the POD = $1.25.
- RTO B: "Through Charge" is the lowest cost zone rate connected with the external control area designated as the POD = $1.20.
- RTO C: "In Charge" is the zone rate where the load is located = $1.00.

- ❖ **W/O rate reciprocity, transmission customer pays the sum of the 3 charges = $3.45 (= $1.25+ $1.20+ $1.00).**
- ❖ **With reciprocity, transactions are broken into 2 components to better facilitate different reciprocity arrangements.**

9

Two Rate Reciprocity Alternatives for Through Transactions

(Three RTO's 1A to 1C treated like a combination of two transactions)

- Alternative 1: The customer pays ½ the source RTO A rate, ½ the RTO B through rate (waives the in and out rate) and ½ the sink RTO C rate. Each RTO collects it's respective revenue and asses a surcharge to cover the remaining shortfall.
- Alternative 2: The customer pays the RTO B through rate and the sink RTO C rate. The revenue is allocated among the RTO's on a flow based method.

10

Alternative 1: Half Tariff Rates & Surcharge Shared Between Three RTO's

(Three RTO's treated like two transactions: 1A to B and B to 1C)

- Transaction from RTO A to RTO B.
  - RTO A waives ½ out charge of $1.25 (= $0.625).
  - RTO B waives in charge
- Transaction from RTO B to RTO C
  - RTO B waives ½ through rate of $1.20 (= $0.60)
  - RTO C waives ½ sink zone 1C rate of $1.00 (=$0.50).
  - Each RTO assess surcharges to cover their respective revenue shortfall.

a) With reciprocity customer pays $1.725= ($0.625 + $0.60 + $0.50).

b) RTO A collects surcharge of $0.625, RTO B collects surcharge of $ 0.60 and RTO C collects surcharge of $0.50. Each RTO determines how its surcharge is to be collected.

d) The Surcharges to cover revenue shortfall are allocated to Transmission Owners within each RTO based on their tariffs.

Alternative 2: Sink & Through Rates w/ Flow Based Revenue Allocation Shared Between Three RTO's

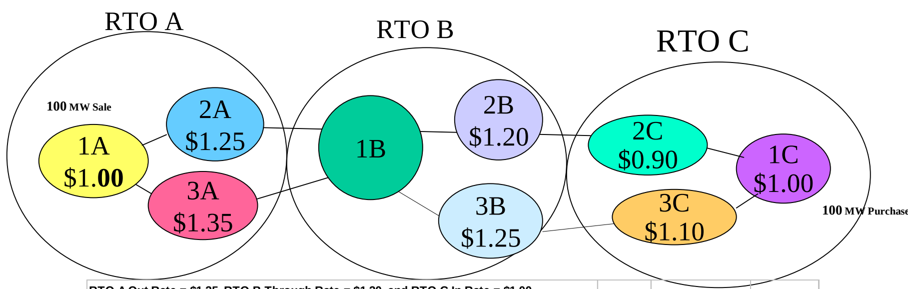
(Three RTO's treated like two transactions: 1A to B and B to 1C)

- Transaction from RTO A to RTO B.
  - RTO A waives out charge of $1.25.
  - Customer pays RTO B through rate of $1. 20.
- Transaction from RTO B to RTO C.
  - RTO B waives out charge since already charged through rate.
  - Customer pays RTO C sink zone rate of $1.00.

a) With reciprocity customer pays $2.20.

b) Revenue of $2.20 is allocated among all three RTO's based on flow. Revenue distributions for all transactions will tend to cover the revenue shortfall.

Example of Flow Based Revenue Allocation For Reciprocity Between Three RTO's



RTO A Out Rate = $1.25, RTO B Through Rate = $1.20, and RTO C In Rate = $1.00

100 MW transaction from RTO A through RTO B and into RTO C.

Customer pays through rate of RTO B ($1.20) and In rate RTO C ($1.00). Total = $ 2.20

Zone	Modeled Transaction MWMiles	% MWMile	Rev Rate Allocation to RTO's	Monthly $ (Allocation*MWMiles)	
1A	12300	12%			
2A	10440	10%	$0.69	$69,131.39	RTO A Receives
3A	10000	10%			
1B	20500	20%			
2B	12600	12%	$0.85	$85,094.54	RTO B Receives
3B	7200	7%			
1C	8800	8%			
2C	12600	12%	$0.66	$65,774.07	RTO C Receives
3C	9750	9%			
Total	104190	100%	$2.20	$220,000.00	

1. Customer pays the RTO B through rate of $1.00/KW-MO and the RTO C in rate of $1.00/KW-MO
2. With reciprocity, the revenue is allocated between all 3 RTO's based on zonal flows as per example above
3. RTO A would collect the dollars for 1A-3A, RTO B collects for 1B-3B and RTO C collects for 1C-3C.

13

Summary of Transmission Pricing Alternatives with & without Reciprocity

Example For 2 RTO's	RTO A Out Charge	RTO B In Charge		RTO Surcharge A, B	Cust Pays	RTO Rev. A, B	Rev. Allocation Method
1A to 1B w/o Reciprocity	$1.25	$1.00	n/a	$0.0, $0.0	$2.25	n/a	n/a
Alt.1 (Half tariff w/ surchrg. to RTO's)	$0.625	$0.50	n/a	$0.625 $0.50	$1.125	$1.25 $1.00	To owners based on RTO tariff
Alt. 2 (Sink rate & flow based allocat.to RTO's)	Waived	$1.00	n/a	n/a n/a	$1.00	$1.00	To owners based on flows
Example for 3 RTO's	**RTO A Out Charge**	**RTO B Through Charge**	**RTO C In Charge**	**RTO Surcharge A, B, C**	**Cust Pays**	**RTO Rev. A, B, C**	**Rev. Allocation Method**
1A to 1B w/o Reciprocity	$1.25	$1.20	$1.00	$0.0, $0.0, $0.0	$3.45	n/a	n/a
Alt.1 (Half tariff w/ surchrg. to RTO's)	$0.625	$0.60	$0.50	$0.625, $0.60, $0.50	$1.725	$1.25 $1.20 $1.00	To owners based on RTO tariff
Alt. 2 (Sink rate & flow based allocat.to RTO's)	Waived	$1.20	$1.00	n/a, n/a, n/a	$2.20	$2.20	To owners based on flows

14

Southwest Power Pool
BOARD OF DIRECTORS
July 20, 2000 Called Meeting

Future Meeting Schedule

Background

The following dates and locations have been approved for future Board of Directors meetings:

Monday and Tuesday, November 6-7, 2000	Wichita, Kansas
Tuesday, May 8, 2001	Little Rock, Arkansas
Tuesday and Wednesday, November 6-7, 2001	Oklahoma City, Oklahoma