Southwest Power Pool
BOARD OF DIRECTORS MEETING
The Westin – Oklahoma City, OK
December 12, 2001

- Summary of Action Items -

1. Approved minutes of the October 17, 2001 Board of Directors meeting as presented.

2. Approved Engineering and Operating Committee recommendations to modify SPP Criteria changes: Criteria 4, Criteria 5.2.4.1, Criteria 7.3.1.3, Criteria 9, and Criteria 10.

3. Approved the 2001 SPP Administrative Budget of $28,488,785 as recommended by the Finance Working Group.

4. Approved SPP Staff's recommendation to terminate ENRON Power Marketing's membership in order to end ENRON's growing debt leaving the remaining financial obligations at approximately $185,000.

5. Elected Mr. Al Strecker, chair, and Mr. J. M. Shafer, vice chair, for two-year terms.

6. Directed finalization of SPP/MISO merger documents by the February 19, 2002 meeting allowing ample time for review and comment by the SPP Board of Directors and Membership.

MINUTES NO. 78

Southwest Power Pool
BOARD OF DIRECTORS MEETING
The Westin – Oklahoma City, Oklahoma
December 12, 2001

Agenda Item 1 – Administrative Items
SPP Chair Mr. Gary Voigt called the meeting to order at 9:58 a.m. The following directors were in attendance or represented by proxy:

Mr. Gene Argo, Midwest Energy, Inc.;
Ms. Kim Casey, Dynegy Marketing and Trade;
Mr. John Stephens, proxy for Mr. David Christiano, City Utilities of Springfield, MO;
Mr. Harry Dawson, OK Municipal Power Authority;
Mr. Michael Deihl, Southwestern Power Administration;
Mr. Jim Eckelberger, and proxy for Mr. Harry Skilton, non-stakeholder directors;
Ms. Trudy Harper, Tenaska Power Services;
Mr. John Marschewski, Southwest Power Pool, Inc.;
Mr. Tom McDaniel, non-stakeholder director;
Mr. Stephen Parr, KS Electric Power Cooperative;
Mr. J. M. Shafer, Western Farmers Electric Cooperative;
Mr. Quentin Jackson, non-stakeholder director;
Mr. Richard Spring, Kansas City Power & Light;
Mr. Al Strecker, OG+E;
Mr. Larry Sur, non-stakeholder director;
Mr. Richard Verret, American Electric Power; and
Mr. Gary Voigt, Chair, Arkansas Electric Cooperative Corp.

There were 41 persons in attendance representing 24 members, 2 guest and 4 regulatory agencies (Attendance List – Attachment 1). The Secretary received 2 proxy statements (Proxies – Attachment 2). Mr. Voigt referred to the agenda (Agenda – Attachment 3) and asked for any modifications to draft minutes of the October 17, 2001 meeting or a motion for approval (10/17/01 Meeting Minutes – Attachment 4). Mr. Sur moved that the minutes be approved as presented. Mr. Dawson seconded this motion, which passed unopposed.

Agenda Item 2 – Engineering & Operating Committee Recommendations
Mr. Mel Perkins reviewed and discussed five recommended modifications to SPP criteria (Criteria 4, Criteria 5.2.4.1, Criteria 7.3.1.3, Criteria 9, and Criteria 10) as distributed in the background material for Board of Directors consideration (EOC recommendations – Attachment 5). Mr. Eckelberger suggested in regard to Criteria 10 that SPP should maintain a back up for the satellite system especially for crisis purposes. Mr. Perkins said that would be noted. Mr. Dixon moved to accept Criteria changes as presented. Mr. Sur seconded and the motion passed unopposed.

Agenda Item 3 – Finance Working Group Recommendations
Ms. Trudy Harper, acting chair of the Finance Working Group consisting of Mr. Dick Dixon, Mr. Gene Argo, Mr. Jim Eckelberger, Mr. Harry Skilton and Mr. John Marschewski, presented

the 2002 Administrative Budget for approval (FWG Recommendation – Attachment 6). Ms. Harper stated that until the merger is finalized, SPP and MISO both need administrative budgets for 2002. Each organization has approached future budgets with the merger in mind and has the same philosophical approach. Concerns were voiced about the need to continue expenditures for the COSMOS project until the merger is complete and RTO status reached. Staff explained that SPP is currently under contract with Accenture for five years, that it would be costly to terminate, and it is important to maintain a valuable asset. Following discussion, Ms. Harper moved to accept the 2002 Administrative Budget of $28,488,785. Mr. Verret seconded and the motion passed with one opposing vote from Mr. Dixon.

Agenda Item 4 – Staff Recommendation on Member Termination

Mr. Nick Brown presented the SPP Staff recommendation to terminate membership of ENRON Power Marketing in light of their December 2, 2001 filing for Chapter 11 bankruptcy protection (Member Termination – Attachment 7). Mr. Brown stated that termination appeared to be in the best interest of both SPP and ENRON ending ENRON's growing debt to SPP as soon as possible. As of December 3, 2001, ENRON has failed to pay SPP its October and November membership assessments. If the Board of Directors terminated ENRON's membership, ENRON's financial obligation to SPP, excluding the delinquent assessments, is approximately $185,000. Staff has contacted ENRON representatives to discuss a membership termination approach but has been unsuccessful in receiving a response. Ms. Harper moved to terminate ENRON Power Marketing, Inc. conditioned on approval or consent of the Bankruptcy Court. Mr. Dawson seconded and the motion passed unopposed.

Agenda Item 5 – Election of Chair & Vice Chair

Mr. Brown in the absence of Mr. Dave Christiano presented Nominating Task Force recommendations to fill the Board of Directors chair and vice chair positions. The Nominating Task Force consists of Mr. Christiano, chair; Ms. Kim Casey; Mr. Stephen Parr; Mr. Michael Deihl; Mr. J.M. Shafer and Mr. Al Strecker. Mr. Brown said that typically the vice chair would move up to chair but in this case Mr. Tom Grennan's resignation has left that position open. Recommended nominees are: Mr. Al Strecker for chair and Mr. J. M. Shafer for vice chair. Mr. Dixon moved to accept the slate of officers as presented. Mr. Dawson seconded and the motion passed unopposed. Mr. Voigt turned over the chair to Mr. Strecker who presided over the remainder of the meeting. Mr. Marschewski commended Mr. Voigt on a job well done.

Agenda Item 6 – SPP/MISO Consolidation Report

Mr. Strecker called on Ms. Stacy Duckett to present the SPP/MISO Consolidation Report (SPP/MISO Consolidation Report – Attachment 8). Ms. Duckett stated that documents for consolidation were about 90-95% complete. The following documents were presented and discussed:

- Purchase and Assumption Agreement
    - Assignment and Assumption Agreement
    - Bill of Sale
    - Certificate of Incorporation
    - Bylaws
    - Services Agreement

- Conditional Withdrawal Agreement
- SPP-MISO Membership Agreement Comparison
- SPP-MISO Tariff Comparison

Following questions and discussion, the Board requested that these documents be finalized before February 19, 2001 allowing ample time for Board of Directors and Members review and comments. All comments are to be directed to Ms. Duckett at sduckett@spp.org.

Adjournment

At 12:39 a.m., Mr. Strecker thanked everyone for their participation and following a short break, reconvened in executive session to discuss personnel matters.

Nicholas A. Brown, Corporate Secretary

Southwest Power Pool
ANNUAL MEETING OF MEMBERS
2001 Fall Meeting – The Westin Hotel – Oklahoma City, Oklahoma
December 12, 2001

ATTENDANCE LIST

Name	System
Dick Dixon	WERE
John Stephens	SPRM
Ted Coombes	SW Power Resources Ass'n
Mike Deihl	SW Power Admin.
David Stidham	SPS
John Marschewski	SPP
Al Strecker	OG&E Elect Srs
Mel Perkins	OG&E
Dennis Constien	OCC/PUD
Mikel Kline	KEPCo
Harry Dawson	OMPA
LARRY SUR	INDEPENDENT
Tom McDaniel	Independent
Jana Lane Phillips	CALPINE
Stacy Duckett	SPP
CARL A MONROE	SPP
Richard A. Spring	KCPL

Southwest Power Pool
ANNUAL MEETING OF MEMBERS
2001 Fall Meeting – The Westin Hotel – Oklahoma City, Oklahoma
December 12, 2001

ATTENDANCE LIST

Name	System
Karen Shea	Dynegy
J.M. Shafer	WFEC
Richard Verret	AEP
Harry Dawson	OMPA
TRUDY HARPER	TENASKA
Tom McDaniel	IND. DIRECTOR
John Stephens	SPRM
Mike Proctor	MoPSC
Mel Perkins	OG&E
Bob Bowser	KEPCo
RICK HENLEY	CWL-JONESBORO AR
Christine Ryan	East Texas Cooperatives
Gary Voigt	AECC
Stephen Parr	KEPCo
Al STRECKER	OG&E
Jim Eckelberger	Independent Director
GENE ARGO	MIDWEST ENERGY, INC.

Southwest Power Pool
ANNUAL MEETING OF MEMBERS
2001 Fall Meeting – The Westin Hotel – Oklahoma City, Oklahoma
December 12, 2001

ATTENDANCE LIST

Name	System
LARRY SUR	INDEPENDENT
KIM CASEY	DYNEGY
MIKE DEIHL	SWPA
DAVID C. STIDHAM	SPS
Mike Apprill	UtiliCorp United
Tom Dunn	SPP
JOHN R. TISDALE	WRIGHT, LINDSEY + JENNINGS
WALTER E. MAY	WRIGHT, LINDSEY & JENNINGS
NICK BROWN	SPP
Michael Desselle	AEP
FRANK ROYSTER	SPP
SAM BRATTON	Ark PSC
Charles Knight	NRG
BILL WYLIE	OG&E

Southwest Power Pool

Board of Directors

PROXY

Harry Skilton hereby appoints James Eckelberger to be his proxy to vote on his behalf at the meeting of the Southwest Power Pool Board of Directors to be held on Wednesday, December 12, 2001.

SIGNED this 10th day of December, 2001

Harry Skilton

Brown, Susan D

From: Christiano, Dave
Sent: Tuesday, December 11, 2001 4:06 PM
To: Brown, Susan D
Subject: Re: Southwest Power Pool

To: John Marschewski
President, Southwest Power Pool

Subject: Proxy for December Board of Directors and Meeting of Members

I hereby transmit my proxy for the subject meetings to John Stephens.
I
request that Nick Brown make my report for the Nominating Committee.

Please accept my best regards for the holiday season.

Sincerely,

David J. Christiano

"Brown, Susan D" <sdbrown@spp.org> on 12/11/2001 03:31:31 PM

To: Dave Christiano/Operations/CUoS@CU
cc:
Subject: Southwest Power Pool

Hello again!
Just letting you know I never received the proxy you were sending. If
you
haven't sent it yet, sorry for the message, I'm just following up.
Thanks!
Susna

Susan Brown
Southwest Power Pool
501-664-0146 ext. 234
Fax: 501-664-9553
email: sdbrown@spp.org

Southwest Power Pool
BOARD OF DIRECTORS MEETING & ANNUAL MEETING OF MEMBERS
2001 Fall Meeting – The Westin Hotel – Oklahoma City, Oklahoma
December 12, 2001

- A G E N D A -

<u>TUESDAY, DECEMBER 11</u>
5:30 – 7:00 p.m. – Reception – 20th Century Room

<u>WEDNESDAY, DECEMBER 12</u>
7 – 8 a.m. – Continental Breakfast- 18th and 19th Century Room
8 a.m. – 3 p.m. – Meetings – 18th and 19th Century Room

Annual Meeting Of Members

1. Administrative Items .... Mr. Gary Voigt
2. President's Report .... Mr. John Marschewski
3. Secretary's Report .... Mr. Nick Brown
4. Operations Report .... Mr. Carl Monroe
5. Financial Report .... Mr. Tom Dunn
6. Nominating Task Force Recommendations .... Mr. David Christiano

Board of Directors Meeting

1. Administrative Items .... Mr. Gary Voigt
2. Engineering & Operating Committee Recommendations .... Mr. Mel Perkins
3. Finance Working Group Recommendations .... Ms. Trudy Harper
4. Staff Recommendation on Member Termination .... Mr. Nick Brown
5. Election of Chair & Vice Chair .... Mr. David Christiano
6. SPP/MISO Consolidation Report .... Mr. John Marschewski
7. Executive Session on Personnel Issues ....

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Hyatt Hotel – Dallas/Ft. Worth Airport
October 17, 2001

- Summary of Action Items -

1. Approved minutes of the August 13, 2001 Board of Directors meeting as presented.

2. Approved recommendation of SPP officers to grant them authority to prepare documents necessary to effect the merger of SPP with Midwest ISO.

3. Directed Mr. Nick Brown to ascertain scope and member interest in participating on a task force to investigate formation of a Transco for SPP members.

4. Approved Engineering and Operating Committee recommendations to modify SPP Criteria changes: Criteria 5, Appendix 7; Criteria 7.1, 7.2, 7.4, 7.5, 7.6, 7.7, and 3.5; Criteria 7.8; Criteria 8; Criteria 12.

Southwest Power Pool
BOARD OF DIRECTORS MEETING
Hyatt Hotel – Dallas/Ft. Worth Airport
October 17, 2001

Agenda Items 1 & 2 – Employee Benefits Working Group Report & SPP/MISO Governance Group Report

SPP Chair Mr. Gary Voigt called the meeting to order at 8:09 a.m. in executive sessions to discuss personnel issues and pending legal matters.

Agenda Item 3 – Administrative Items

At 10:14 a.m., Mr. Voigt reconvened the meeting in open session. The following directors were in attendance or represented by proxy:

- Mr. Nick Akins, proxy for Mr. Richard Verret, American Electric Power;
- Mr. Gene Argo, Midwest Energy, Inc.;
- Ms. Kim Casey, Dynegy Marketing and Trade;
- Mr. Harry Dawson, OK Municipal Power Authority;
- Mr. Jim Eckelberger, non-stakeholder director;
- Mr. Tom Grennan, Western Resources;
- Ms. Trudy Harper, Tenaska Power Services;
- Mr. Quentin Jackson, and proxy for Mr. Harry Skilton, non-stakeholder directors;
- Mr. John Marschewski, Southwest Power Pool, Inc., and proxy for Mr. Tom Grennan, Western Resources;
- Mr. Tom McDaniel, non-stakeholder director;
- Mr. John Oxendine, non-stakeholder director;
- Mr. Gene Reeves, proxy for Mr. Michael Deihl, Southwestern Power Administration;
- Mr. J. M. Shafer, Western Farmers Electric Cooperative, and proxy for Mr. Stephen Parr, KS Electric Power Cooperative;
- Mr. Richard Spring, Kansas City Power & Light;
- Mr. John Stephens, proxy for Mr. David Christiano, City Utilities of Springfield, MO;
- Mr. Al Strecker, OG+E;
- Mr. Larry Sur, non-stakeholder director; and
- Mr. Gary Voigt, Chair, Arkansas Electric Cooperative Corp.

There were 34 persons in attendance representing 15 members, 2 guests and 1 regulatory agency (Attendance List – Attachment 1). The Secretary received 6 proxy statements (Proxies – Attachment 2). Mr. Voigt referred to agenda item 3 (Agenda – Attachment 3) and asked for any necessary modifications to draft minutes of the August 13, 2001 meeting or a motion for approval (8/13/01 Meeting Minutes – Attachment 4). Mr. Larry Sur moved that the minutes be approved as presented. Mr. Richard Spring seconded this motion, which passed unopposed.

Agenda Item 4 – Southwest Power Pool/Midwest ISO Merger

Mr. John Marschewski provided background comments on the investigation process related to a merger of SPP and the Midwest ISO and then asked Mr. Nick Brown for a detailed report. Mr. Brown outlined work to date by SPP and Midwest ISO (MISO) on the due diligence review of the proposed merger and referred to and summarized an initial staff report distributed on September 20, 2001 (SPP/MISO Merger Report – Attachment 5) and also a memorandum from SPP and MISO presidents describing the business structure for the combination (Merger Letter – Attachment 6). Mr. Brown described alternatives with other entities and the business rationale for merging with MISO. Mr. Brown summarized the findings of the business and financial reviews as indicating that the combined organizations will offer greater efficiency and effectiveness. Mr. Brown stated that SPP had employed the services of Wright, Lindsey, & Jennings to handle legal aspects of the merger and introduced Mr. John Tisdale and Mr. Walter May. Mr. Tisdale explained that many documents had been exchanged and reviewed in the due diligence process between SPP and MISO and answered questions concerning these issues.

Mr. Brown stated that managements were recommending a combination structure with the following attributes:

- Transfer of SPP assets and liabilities to MISO;
- MISO governance, management, and membership agreement reconfigured with new corporate name;
- SPP remaining as reliability council with purchase of services from new company at cost;
- SPP members to be reimbursed for their contribution to SPP start-up costs by new company; and
- Transcos continue to be allowed as previously agreed.

Mr. Brown then presented the following SPP officers' recommendation:

> SPP officers recommend that the Board of Directors grant them the authority to prepare documents necessary to effect the merger of SPP with the Midwest ISO. Final approval of the transaction will be requested after the proposed documents have been prepared and reviewed by the SPP Board of Directors.

Ms. Trudy Harper moved to accept this recommendation. Mr. Tom McDaniel seconded the motion, which passed with one abstention by Mr. Nick Akins (AEP). Ms. Harper requested that proposed documents be distributed to members for their information and comment prior to final Board consideration. Ms. Kim Casey requested that SPP recognize the overlap of reliability, security, and tariff and facilitate a smooth distribution between the three responsibilities to reduce the potential for conflict and duplication.

Mr. Harry Dawson expressed a desire to set up a study group to determine interest in forming a transco for SPP members. After some discussion, Mr. Voigt asked that Mr. Brown coordinate this activity.

<u>Agenda Item 5 – Engineering & Operating Committee Report</u>

Mr. Carl Monroe (SPP) presented the Engineering & Operating Committee report. Mr. Monroe reviewed and discussed six recommended modifications to SPP criteria (Criteria 5, Appendix 7; Criteria 7.1, 7.2, 7.4, 7.5, 7.6, 7.7, and 3.5; Criteria 7.8; Criteria 8; Criteria 12) as distributed in the background material for Board of Directors consideration (EOC recommendations – Attachment 7). Following discussion, Mr. John Oxendine moved to accept the recommended changes. Mr. Harry Dawson seconded the motion, which passed unopposed.

Agenda Item 4 – COSMOS System Project Management Report

Mr. Carl Monroe also presented the COSMOS System Project Management Report. Mr. Monroe referred to a slide presentation and displayed posters explaining this project and its status (COSMOS System Project Management Report – Attachment 8). To date $20 million has been expended with another $20 million committed over the next 5 years. Mr. Monroe asked for interested parties to participate in a mini market test of the COSMOS system and stated a recommendation for full implementation of this project may be ready by the next Board of Directors meeting.

Future Meeting and Adjournment

Mr. Marschewski suggested a rescheduling of the November Board of Directors and Annual Meeting of Members to allow time for papers to be drawn up for the SPP/MISO merger as approved. A general consensus was reached to hold these meetings in a one-day format in Oklahoma City on either December 11 or 12, 2001.

With no further business, Mr. Voigt adjourned the meeting at 11.40 p.m. and thanked everyone for their participation.

Nicholas A. Brown, Corporate Secretary

Southwest Power Pool
ENGINEERING AND OPERATING COMMITTEE
Recommendation to the Board of Directors
December 11-12, 2001

Engineering and Operating Committee is recommending Criteria changes in the following sections:

1. Criteria 4
2. Criteria 5.2.4.1
3. Criteria 7.3.1.3
4. Criteria 9
5. Criteria 10

Southwest Power Pool
ENGINEERING AND OPERATING COMMITTEE
Recommendation to the Board of Directors
December 11-12, 2001

SPP Criteria 4
ATC/TRM/CBM Determination

Background

Several changes have occurred which impact Regional Transmission Planning and the interconnected reliability councils. As a result, NERC developed planning standards to establish a unified means of ensuring the interconnected system's security. In response, the SPP Engineering and Operating Committee (EOC) formed the Planning Standards Task Force to review current SPP Criteria for compliance with these standards. At the October 1998 EOC meeting, the EOC approved recommendations in a report titled SPP Review and Evaluation of NERC Planning Standards. One recommendation of the report was a review of the SPP Criteria 4 for ATC/TTC calculation and determination process. The EOC assigned this review to the Transmission Assessment Working Group (TAWG). In response, the Criteria 4 Task Force, formed under the TAWG, began to review NERC planning standards in coordination with the current FERC approved SPP Open Access Transmission Tariff (OATT) processes. The Criteria 4 Task Force then began work converting the existing path based ATC determination method outlined in the existing Criteria 4 to a flowgate/constraint based ATC calculation methodology.

Recent Activity

An update on Criteria 4 was presented to the EOC at the March 2001 meeting with information that the TAWG anticipated completion of the criteria by March 29th, 2001. At this meeting, the EOC commissioned that all criteria be revisited. Since that time the Criteria 4 Task Force completed their work and disbanded passing the new criteria language to the TAWG for working group approval. With minor changes, both the Transmission Assessment Working Group and the Security Working Group reviewed and approved the document for EOC acceptance.

Analysis

SPP OATT:
The Criteria 4 Task Force reviewed the most current FERC approved SPP OATT document to identify any tariff related ATC coordination and determination requirements for both the short term and long term horizons. Operational and business practices to facilitate the SPP OATT were reflected in the new criteria language.

NERC Compliance Standards:
NERC 1.E. standards were examined for regional calculation and determination requirements of ATC, TTC, TRM and CBM practices. Criteria language was crafted to capture all current practices on both the operational and planning

horizons. With the exception of a TTC methodology, (FERC waiver based on utilization of a constraint based approach to ATC determination) documentation of current practices that address all NERC 1.E. requirements were clearly indicated citing the appropriate sections of Criteria 4. On January 15, 2001, the SPP Compliance Manager submitted the draft criteria to the NERC ATC Working Group for review and comment. Comments received from the NERC working group were addressed and changes were submitted on February 26, 2001 in a cooperative manner, even though, due to unaccounted circumstances, the ATCWG failed to receive this draft. However, the TAWG is confident the final approved draft addresses all issues identified by the NERC ATC Working Group and will be submitted at the next NERC compliance submittal. The TAWG understands that any future changes to NERC 1.E. standards such as CBM and TRM calculations, can be addressed at that time with recommended changes to criteria for the purpose of NERC compliance.

Conclusion
The Criteria 4 Task Force developed the attached document from review of the latest official NERC 1.E. standards and SPP Open Access Transmission Tariff practices on ATC/TTC/TRM/CBM calculations. The TAWG has determined the Criteria 4 Task Force has made every effort to accurately reflect current ATC/TRM/CBM practices in relation to the SPP Open Access Transmission Tariff and NERC 1.E. compliance standards. Any changes to NERC 1E compliance standards may be addressed when they become official.

Recommendation
The Engineering and Operating Committee requests the recommended Criteria 4 language be incorporated as a part of the SPP Criteria.

Approved

Transmission Assessment Working Group	June 2001
Security Working Group	June 2001
Engineering and Operating Committee	October 2001

Action Requested
Approve the attached SPP Criteria 4 as recommended by the TAWG

Attachments:
SPP Criteria 4

Southwest Power Pool, Inc.

TAWG Criterion 4 Task Force

CRITERION 4 UPDATE

TAWG/SWG APPROVED, 6-6-2001

MAINTAINED BY
SOUTHWEST POWER POOL
TRANSMISSION ASSESSMENT WORKING GROUP

PUBLISHED: pending approvals
LATEST REVISION: November 1998

4.0 REGIONAL CALCULATION OF AVAILABLE TRANSFER CAPABILITY

SPP takes a regional approach in the determination of Available Transfer Capability (ATC). The regional approach calls for SPP to evaluate the inter-area transfer capability of its Transmission Owners. This approach provides a high level of coordination between ATC reported by SPP and Transmission Owners on SPP Open Access Same-time Information Network (OASIS) nodes. Likewise, when Transmission Owners calculate ATC, they are responsible to coordinate the ATC between their areas. If there is a dispute concerning the ATC, the SPP Transmission Assessment Working Group (TAWG) will act as the technical body to determine the ATC to be reported.

This Criteria provides Transmission Owners and the SPP Transmission Provider flexibility to revise the ATC as needed for changes in operating conditions, while providing for unique modeling parameters of the areas. The SPP Transmission Provider calculations do not preclude any studies made by Transmission Owners in accordance with their individual tariffs, which may contain specific methodologies for evaluating transmission service requests.

Transfer capabilities are calculated for two different commercial business applications; a) for use as default values for Transmission Owners to post on their OASIS node for business under their transmission tariffs and b) for use by SPP in administering the SPP Open Access Transmission Tariff (SPP OATT).

The SPP utilizes a “constrained element” approach in determining ATC. This approach is referred to as a Flowgate ATC methodology. Constrained facilities, termed “Flowgates”, used in this approach are identified primarily from a non-simultaneous transfer study using standard incremental transfer capability techniques that recognize thermal, voltage and contractual limitations. Stability limitations are studied as needed. Flowgates serve as proxies for the transmission network and are used to study system response to transfers and contingencies. Using Flowgates with pre-determined ratings, this process is able to evaluate the ATC of specific paths on a constrained element basis (Flowgate basis) while considering the simultaneous impact of existing transactions.

The calculation of ATC is a very complex and dynamic procedure. SPP realizes that there are many technical and policy issues concerning the calculation of ATC that will evolve with industry changes. Therefore, the SPP Security Working Group and the SPP Transmission Assessment Working Group will have the joint authority to modify the implementation of this Section of the Criteria based on experience and improvements in technology and data coordination. Any changes made by these groups will be subject to formal approval as outlined in the SPP By-laws at the first practical opportunity.

4.1 DEFINITIONS

4.1.1 Base Loading, Firm and Non-Firm (FBL & NFBL)

The determined loading on a Flowgate resulting from the net effect of modeled existing transmission service commitments for the purpose of serving firm network load and impacts from existing OATT OASIS commitments.

4.1.2 Capacity Benefit Margin

The amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

4.1.3 Contractual Limit

Contractual arrangements between Transmission Providers that define transfer capability between the two.

4.1.4 Critical Contingency

Any generation or transmission facility that, when outaged, is deemed to have an adverse impact on the reliability of the transmission network.

4.1.5 Designated Network Resources (DNR)

Any designated generation resource that can be called upon at anytime for the purpose of serving network load on a non-interruptible basis. The designated generation resource must be owned, purchased or leased by the owner of the network load.

4.1.6 Emergency Voltage Limits

The operating voltage range on the interconnected system that is acceptable for the time sufficient for system adjustments to be made following a Critical Contingency.

4.1.7 Firm Available Transfer Capability (FATC)

The determined transfer capability available for firm Transmission Service as defined by the FERC pro forma Open Access Transmission Tariff (OATT) or any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.8 First Contingency Incremental Transfer Capability (FCITC)

NERC Transmission Transfer Capability, reference document (May 1995) defines FCITC as:

"The amount of power, incremental and above normal base transfers, that can be transferred over the interconnected transmission systems in a reliable manner based on all of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits,
2. The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission circuit, transformer or generating unit, and,
3. After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facilities loadings are within emergency ratings and all voltages are within emergency limits."

4.1.9 Flowgate

A selected transmission element or group of elements acting as proxy for the transmission network representing potential thermal, voltage, stability and contractual system constraints to power transfer. The process of determining the reliability issues for which a Flowgate is representative of and by which a Flowgate is established is outlined in the Flowgate Determination section.

4.1.10 Line Outage Distribution Factor (LODF)

The percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

4.1.11 Local Area Problem

A Transmission Owner may declare a facility under its control a Local Area Problem if it is overloaded in either the base case or contingency case prior to the transfer. If a member declares a facility a Local Area Problem, the member may neither deny transmission service nor request NERC Transmission Loading Relief for that defined condition.

4.1.12 Monitored Facilities

Any transmission facility that is checked for predefined transmission limitations.

4.1.13 Non-firm Available Transfer Capability (NFATC)

The determined transfer capability available for sale for non-firm Transmission Service as defined by the NERC pro forma Open Access Transmission Tariff for any direction of interest on a transmission network between generation groups and/or system load for which commercial service may be desired.

4.1.14 Normal Voltage Limits

The operating voltage range on the interconnected system that is acceptable on a sustained basis.

4.1.15 Open Access Transmission Tariff (OATT)

FERC approved Pro-Forma Open Access Transmission Tariff.

4.1.16 Operating Horizon

Time frame for which Hourly transmission service is offered. The rolling time frame is twelve to 36 hours with a 12 noon threshold. It includes the current day, and after 12 noon, the remainder of the current day and all hours of the following day.

4.1.17 Operating Procedure

Any policy, practice or system adjustment that may be automatically implemented, or manually implemented by the system operator within a specified time frame, to maintain the operational integrity of the interconnected electric systems. If an Operating Procedure is submitted to the SPP in writing and states that it is an unconditional action to implement the procedure without regard to economic impacts or existing transfers, then the Operating Procedure will be used to allow transfers to a higher level.

4.1.18 Outage Transfer Distribution Factor (OTDF)

The percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service.

4.1.19 Participation Factor

The percentage of the total power adjustment that a participation point will contribute when simulating a transfer.

4.1.20 Participation Points

Specified generators that will have their power output adjusted to simulate a transfer.

4.1.21 Planning Horizon

Time frame beyond which Hourly transmission service is offered.

4.1.22 Power Transfer Distribution Factor (PTDF)

The percentage of power transfer flowing through a facility or a set of facilities for a particular transfer when there are no contingencies.

4.1.23 Power Transfer Voltage Response Factor (PTVF)

The per unit amount that a facility's voltage changes due to a particular transfer level.

4.1.24 SPP Open Access Transmission Tariff (SPP OATT)

The Southwest Power Pool Regional FERC approved Open Access Transmission Tariff

4.1.25 Transfer Distribution Factor (TDF)

A general term, which may refer to either PTDF or OTDF – The TDF represents the relationship between the participation adjustment of two areas and the Flowgates within the system.

4.1.26 Transfer Test Level

The amount of power that will be transferred to determine facility TDFs for use in DC linear analysis.

4.1.27 Transmission Owner (TO)

An entity that owns transmission facilities which are operated under a FERC approved OATT.

4.1.28 Transmission Provider (TP)

An entity responsible for administering a transmission tariff. In the case of the SPP OATT, SPP is the Transmission Provider. An SPP member may be its own Transmission Provider if the member continues to sell transmission service under the terms of its own tariff.

4.1.29 Transmission User (TU)

Any entities that are parties to transactions under appropriate tariffs.

4.1.30 Transmission Reliability Margin (TRM)

The amount of Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

4.1.31 TRM multipliers (a & b)

"a"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Planning Horizon

"b"-multiplier; a factor between 0 and 1 indicating the amount of TRM not available for non-firm use during the Operating Horizon

4.2 CONCEPTS

4.2.1 Transfer Capability

Transfer capability is the measure of the ability of the interconnected electric systems to reliably move or transfer power from one area to another over all transmission circuits (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). Transfer capability is also directional in nature. That is, the transfer capability from area A to area B is not generally equal to the transfer capability from area B to area A.

Some major points concerning transfer capability analysis are briefly outlined below:

1. **System Conditions** - Base system conditions are identified and modeled for the period being analyzed, including projected customer demand, generation dispatch, system configuration and base reserved and scheduled transfers.

2. **Critical Contingencies** - During transfer capability studies, both generation and transmission system contingencies are evaluated to determine which facility outages are most restrictive to the transfer being analyzed.

3. **System Limits** - The transfer capability of the transmission network can be limited by thermal, voltage, stability or contractual considerations.

Thermal and voltage transfer limits can be determined by calculating the First Contingency Incremental Transfer Capability. Stability studies may be performed by the Transmission Owners at their discretion. Any known stability limits, which are determined on a simultaneous basis, and all contractual limits will be supplied by each Transmission Owner in writing to the Transmission Provider and the TAWG.

4.2.2 Available Transfer Capability

NERC Available Transfer Capability Definitions and Determinations, reference document (June 1996) states: “Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.”

SPP determines ATC as a function of the most limiting Flowgate of the path of interest. How limiting a Flowgate is to a path is based on two aspects: (1) The determined firm or non-firm Available Flowgate Capacity (FAFC or NFAFC) for that Flowgate, and (2) the TDF for which that Flowgate responds to power movement on the path under evaluation.

The common relationship between the identified limiting Flowgate and the path is the Transfer Distribution Factor (TDF). This is mathematically expressed as follows:

Firm ATC = the firm Available Flowgate Capacity divided by the Transmission Distribution Factor
(FATC = FAFC/TDF)
of the associated path.

Likewise,

Non-Firm ATC = the non firm Available Flowgate Capacity divided by the Transmission Distribution Factor
(NFATC = NFAFC/TDF)
of the associated path.

Path ATC is determined by identifying the most limiting Flowgates to the path in question. Each Flowgate represents a potential limiting element to any path within a system. Therefore, each Flowgate with known Transfer Distribution Factor (TDF) can be translated into path ATC. However, the Flowgate that produces the most limiting path ATC is the key Flowgate for that path.

The calculation of path ATC using this method is based on the ratio of the TDF into the remaining capacity of a Flowgate, (non firm Available Flowgate Capacity or firm Available Flowgate Capacity). Once a group of potential limiting elements has been selected, then all values pertaining to ATC can be translated based on the TDF.

4.2.3 Response Factors

Response Factors are numerical relationships between key adjustments in the transmission system and specific transmission components being monitored. They provide a linear means of extrapolation to an anticipated end for which decisions can be made. While there are obviously uncountable numbers of responses occurring in a system while transferring power, there are only a few that aid in the process of determination of ATC.

(1) **Transfer Distribution Factor** - The Transfer Distribution Factor (TDF) is a general term referring to either PTDF or OTDF. The relationship between adjustments in participation points associated with a specific path and the identified Flowgate in the system is the TDF. Depending on the Flowgate type, the TDF may specifically represent the response in the system to certain types of pre-identified system limitations as mentioned in the System Limitations section of the criteria.

(2) **Line Outage Distribution Factor** - The Line Outage Distribution Factor (LODF) is the percent of the power flowing across the contingency facility that transfers over the monitored facility when the contingency facility is switched out of service.

(3) **Power Transfer Distribution Factor** - The Power Transfer Distribution Factor (PTDF) is the percentage of a power transfer that flows through a facility or a set of facilities for a particular transfer when there are no contingencies. PTDF type Flowgates are used for representing Thermal, Voltage, Stability and Contractual Limitations. A PTDF Flowgate must have a PTDF at or above the percentage outlined in NERC Operating Policies Transmission Loading Relief curtailment thresholds to be considered a valid limit to transfer, except in long-term evaluations where no TDF threshold is used.

(4) **Outage Transfer Distribution Factor** - The Outage Transfer Distribution Factor (OTDF) is the percentage of a power transfer that flows through the monitored facility for a particular transfer when the contingency facility is switched out of service. OTDF type Flowgates typically represent contingency based thermal limitations within the system. They can also be used to represent Stability limitations. Monitored Facility must have an OTDF at or above the percentage outlined in NERC Operating Policies Transmission Loading Relief curtailment thresholds to be considered a valid limit to transfer, except in long-term evaluations where no TDF threshold is used.

(5) Power Transfer Voltage Factor - The Power Transfer Voltage Factor (PTVF) is the per unit amount that a facility's voltage changes due to a particular transfer level. A facility must have a PTVF at or above 0.02 p.u. to be considered a valid limit to transfer.

4.2.4 Transfer Capability Limitations

The electrical ability of the interconnected transmission network to reliably transfer electric power may be limited by any one or more of the following:

1. **Thermal Limits** - Thermal limits establish the maximum amount of electrical current that a transmission circuit or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it violates public safety requirements. Normal and emergency transmission circuit ratings are defined in the SPP Rating of Equipment.

2. **Voltage Limits** - System voltages must be maintained within the range of acceptable minimum and maximum voltage limits. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a blackout of portions of or the entire interconnected network. Acceptable minimum and maximum voltages are network and system dependent. The Normal Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed in kilovolts, that is acceptable on a sustained basis. The Emergency Voltage Limit range is the operating voltage range on the interconnected systems, above or below nominal voltage and generally expressed

in kilovolts, that is acceptable for the time sufficient for system adjustments to be made following a facility outage or system disturbance. Voltage limits will be as specified in the Planning Criteria section of the SPP Criteria: Regional Transmission Planning.

3. **Stability Limits** - The transmission network must be capable of surviving disturbances through the transient and dynamic time periods following a disturbance. Specific Stability Limits Criteria is found in the SPP Criteria: Regional Transmission Coordinated Planning.

4. **Contractual Requirements**- Some Transmission Owners have contractual arrangements that contain mutual agreements regarding the power transfer available between them. These contractual arrangements have been approved by the appropriate regulatory agencies. The NERC Operating Policies inherently recognize contract requirements that may limit the power transfer between Transmission Owners. Some contract requirements are discussed in NERC Operating Policy 3 – Interchange.

   The limiting conditions on some portions of the transmission network can shift among thermal, voltage, stability and contractual limits as the network operating conditions change over time

4.2.5 Invalid Limits

The procedures outlined in criteria may lead to identification of certain limiting facilities that are invalid. Reasons may include, but are not limited to:

- An invalid contingency generated as a generic single outage, which is not valid without the outage of other facilities.
- Incorrect ratings. Ratings will be corrected and the limiting transfer level recalculated.
- The rating used may be directional in nature (directional relaying) and may not be valid for the direction of flow.
- The limiting facility is the result of over-generation/under-generation at a participation point.
- The contingency is considered improper implementation of an operating procedure.
- The facility represents an equivalent circuit.

- The limiting facility is declared a Local Area Problem.

Any limiting facility determined to be invalid due to modeling error that could be corrected must be corrected by the next series of seasonal calculations.

4.2.6 Flowgates

Flowgates are selected power transmission element groups that act as proxies for the power transmission system capable of representing potential thermal, voltage, stability and contractual system limits to power transfer. There are two types of Flowgates;

- OTDF Flowgate; Composed of usually two power transmission elements in which the loss of one (contingency facility) can cause the other power transmission element (monitored facility) to reach its emergency rating.
- PTDF Flowgate; Composed of one or more power transmission elements in which the total pre-contingency flow over the flowgate cannot excede a predetermined limit. Either with the power transmission system intact or with a contingency elsewhere, the Flowgate can be selected to represent a thermal, voltage, stability or contractual limit.

Once a set of limiting elements have been identified, as potential transfer constraints, they can be grouped with their related components and identified as unique Flowgates. The rating of the Flowgate is called the Total Flowgate Capacity (TFC) of the Flowgate and is monitored and used for evaluation of all viable transfers for commerce.

To the extent that the impedance network models are similar with similar participation patterns, the same Flowgates can be monitored in other network models for purposes of evaluating the impact of additional transactions on the network. Of course, each network model will be subtly different therefore it is important that engineering judgment is exercised regarding the validity of applying existing Flowgates to a new network model.

4.2.7 Total Flowgate Capacity (TFC)

The Flowgate and its Total Flowgate Capacity are pre-defined. A Flowgate is intended to limit the amount of power allowed to flow over a defined element set. This TFC may reflect several possible types of system limitations as described in the Limitations Section.

For OTDF Flowgates representing thermal overloads, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility.

For PTDF Flowgates, the TFC represents the total amount of power that can flow over a defined element set under pre-contingency conditions.
Again, limit types could be:

1) Thermal limits under normal operating conditions or linked contingency events,
2) Voltage limits under normal operating conditions or linked contingency events,
3) Stability limits under normal operating conditions or linked contingency events, or
4) Contractual limits.

Flowgates are selected based on the impacts of power transfer in an electrical network and will be evaluated on a regular basis and revised as needed to ensure thorough representation of the system they are representing.

Each Flowgate represents a possible limitation within a network and in itself has a Flowgate rating (TFC) and an Available Flowgate Capacity (AFC) which can be translated via the path response factor (TDF) to a path Available Transfer Capability (path ATC) for any path.

4.2.8 Flowgate Capacity

4.2.8.1 Total Flowgate Capacity (TFC)

A Flowgate acts as proxy to path transfer limitations. This allows additional transfer capability on a path based on the additional loading that can be incurred. The determination of additional loading that can be incurred on a Flowgate begins first with the determination of the maximum loading that can be allowed on a PTDF Flowgate or on the monitored facility of an OTDF Flowgate during its associated contingency. This maximum loading is termed Total Flowgate Capacity (TFC).

4.2.8.2 Available Flowgate Capacity (AFC)

The available capacity on a Flowgate for additional loading for new power transfers is determined by taking the Total Flowgate Capacity (TFC) and removing the Flowgate Base Loading (FBL) and the Impacts due to existing system commitments and any transmission margins.

AFC = TFC – FBL – Impacts of existing commitments – transmission margins

4.2.8.3 Firm and Non-Firm Available Flowgate Capacity (FAFC and NFAFC)

Path ATC is classified as firm or non-firm. This distinction is made when determining the Available Flowgate Capacity (AFC) remaining for path ATC. AFC is classified as firm or non-firm depending on the types of existing commitments considered for Impacts. This is realized in the formula for Available Flowgate Capacity:

(AFC = TFC – FBL – Impacts of existing commitments – transmission margins).

4.2.9 System Impacts

4.2.9.1 Impacts of Existing Commitments

In order to simultaneously account for impacts of all commitments to all paths at any given instant in time, it is necessary to devise a system that allows for fluctuation in the number of and the magnitude of system commitments on each path within an acceptable amount of time, for the purpose of providing transmission service in a competitive manner.

Existing transmission commitments beyond those modeled as native load and related generation commitments can be found on the OASIS. However, before impacts of OASIS posted reservations can be calculated, they must first be interpreted – carefully examined for peculiar individual characteristics. Due to the nature of the OASIS and the rules therein, posted reservations sometimes require interpretation as to their actual value to apply toward the transmission network.

The following are examples of evaluations that are performed:

- Recognize and adjust for duplicate reservations by multiple providers to complete one transaction.
- Adjust for reservations that may have changed status or have been replaced by another reservation.
- Check for proper reflection of capacity profiles of reservations.
- Distinguish status and class of reservations such as Study, Accepted, Confirmed, Firm, and Non-Firm status to determine their proper impact level.

4.2.9.2 Positive Impacts

The scope of "Impacts of existing commitments" in the formula for AFC incorporates both the calculated positive impacts and counter impacts of non-firm and firm service commitments. A positive impact is determined as having the effect of increasing the loading on a Flowgate in the direction of the Flowgate. Positive impact types are sorted into those resulting from firm and non-firm service commitments. To determine firm or non-firm Available Flowgate Capacity, the appropriate impacts are applied to make up the "Impacts of existing commitments" in the above formula. Additionally, counter impacts are considered depending on firm or non-firm determinations.

4.2.9.3 Counter Impacts

Counter impacts are those impacts due to transfers that act to relieve loading on limiting elements. Counter impact types are sorted into those resulting from firm and non-firm service commitments. These flows are not traditionally accepted as valid under the pretense that any reservation that may cause such a loading relief is not actually doing so until it has been scheduled. To consider counter-flows in transfer capability studies is to assume a high probability of scheduling.

4.2.10 Monitored Facilities

During the Flowgate determination process those facilities monitored for pre-defined limiting conditions. Mandatory Monitored Facilities, for use in these calculations, are all facilities operated at 100 kV and above and all interconnections between Transmission Providers. Other facilities operated at lower voltage levels may be added to the

Monitored Facilities list at the discretion of the Transmission Providers or Transmission Owners.

In defining Flowgates, the Monitored Facilities are those components of a Flowgate that remain in service following the defined contingency.

4.2.11 Critical Contingencies

Those facilities that, when outaged, are deemed to have an adverse impact on the reliability of the transmission network. These facilities may be transmission facilities, including multi-terminal lines, or generating units. All interconnections of an area will be considered Critical Contingencies, regardless of voltage level as will the largest generating unit in the area.

4.3 RELIABILITY MARGINS

Transmission margins are very important to the reliability of the interconnected network in an Open Access environment. The NERC "Available Transfer Capability Definitions and Determination Reference Document" defines Transmission Reliability and Capacity Benefit margins (TRM, CBM).

When using Flowgates as a means to represent a system's constraints, it is necessary to translate reliability margins, TRM and CBM, to a unique TRM and CBM for each Flowgate. Margins are the required capacities that must be preserved for the purpose of moving power between areas during specific emergency conditions. Since a margin is a preservation of transfer capacity, the margin itself will have an impact on the most limiting element between the two areas for which it is reserved.

All studies for the purpose of assessing TRM and CBM will only include generation units located within the transmission system for which the Transmission Provider is responsible. These generation units may also include those not specifically designated to serve network load connected to transmission systems within the Transmission Provider system. However, the method by which a Transmission Provider is to determine TRM and CBM shall not vary from that described herein with the exception of assessing facilities located outside of SPP regional structure/bounds.

4.3.1 Transmission Reliability Margin (TRM)

TRM on a Flowgate basis is that amount of reserved Flowgate capacity necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The following factors shall be considered by SPP in the determination of TRM.

- Load Forecast

Transmission Providers will forecast hourly load for the next seven days for all applicable control areas.

Beyond seven days, Transmission Providers will project a demand based on seasonal peak load models for all applicable Transmission Owners. These load levels will be the projected peaks for the time frame for which the forecast applies.

- Variations in Generation Dispatch

Variations to generation patterns constitute a viable concern. Generation dispatch in near-term models will be based on real-time snapshots of network system conditions. For the longer-term horizons, whenever possible, generation dispatch information provided by generation owners will be applied to the ATC calculations. However, it is recognized that longer-term dispatch is probably unknown to the generation controlling entities themselves except for base-load and must run type units.

- Unaccounted Parallel Flows

Parallel flows can be an issue if pertinent data to the ATC calculations are not shared among the transmission providers and those transactions that have multiple wheeling parties are not identified. Provision in the SPP OATT have reduced the impacts of these transactions within SPP and between SPP and other regions.

Transmission Owners of facilities that are impacted by unaccounted parallel flows or variations in dispatch may request additional TRM for their impacted Flowgates from the TAWG. Such requests must be in writing, must document the parallel flow impacts or the variance in historical dispatch, and be accompanied by analysis or documentation supporting the additional TRM requirements. The TAWG shall have the authority to grant or reject requests for the additional TRM requests.

- SPP Operating Reserve Sharing

The SPP Operating Reserve Sharing program was instituted to provide both reliability and economic benefits to its members. This program reduces the amount of internal operating reserves each entity is required to maintain while providing an automated way of allocating resources on a region wide level to ensure quick recovery for the loss of any unit. Transmission facilities must be able to support the automatic implementation of the Reserve Sharing program. To that end, TRM on the Flowgates will provide enough capacity to withstand the impact of the most critical generation loss to that facility. All generation contingencies will be simulated by the Operating Reserve Sharing algorithm to determine the highest impact on each Flowgate. This capacity will be included in TRM.

- Counter Flow Impacts

Another factor to consider in the SPP TRM process is that for the planning horizon, which is primarily next day and beyond, the counter flow impacts of reservations on the Flowgates are removed with the exception of Designated Network Resources. This provides an inherent margin in the calculation which along with the constant TRM provided by the reserve sharing allocation, is a proxy for the generation variation.

4.3.2 TRM Coordination

The TRM specified on a Flowgate represents a transmission margin that the transmission system needs to maintain a secure network under a reasonable range of uncertainties in system conditions. As such it is not necessarily an import or export quantity specifically. The Automatic Operating Reserve Sharing portion is determined by centralized Regional study based on the SPP Operating Reserve Sharing Criteria. Any additional TRM may be requested by the Flowgate owner/s, subject to review by the SPP TAWG.

4.3.3 TRM Availability for Non-firm Service

To maximize transmission use to the extent reliably possible, Transmission Providers may sell TRM on a non-firm basis. The ‘a’ and ‘b’ multipliers facilitate this purpose in the calculations. However, a contingency or long-term outage to a high impact unit may result in the curtailment of non-firm schedules and displacement of non-firm reservations sold within the TRM.

4.3.4 TRM Calculation Frequency

The Operating Reserve Sharing portion of the TRM will be determined annually for each season (Spring, Summer, Fall, Winter). This process is outlined in the SPP Criteria under Operating Reserves and the Operating Reserve Share Program Procedures. Flowgate owner requests for additional TRM may be submitted at any time for consideration at the next TAWG meeting. The submittal should include justification and rational in writing for the requested additional TRM. The TAWG shall have authority to reject or grant such requests.

4.3.5 Capacity Benefit Margin (CBM)

CBM on a Flowgate basis is the amount of Flowgate capacity reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

SPP will use a probabilistic approach for Regional and sub-regional Generation Reliability assessments. These assessments will be performed by the SPP on a biennial basis. Generation Reliability assessments examine the regional ability to maintain a Loss of Load Expectation (LOLE) standard of 1 day in ten years. The SPP capacity margin Criteria requires each control area to maintain a minimum of 12% capacity margin for steam-based utilities and 9% for hydro-based utilities. Historical studies indicate that the LOLE of one day in ten years can be maintained with a 10% - 11% capacity margin. As a normal practice, default values for CBM will be zero for calculations of ATC for some or all of the following reasons:

- the existing level of internal capacity margin of each member is adequate
- historical reliability indicators of transmission strength of the SPP area
- Open Access transmission usage environment allows greater purchasing options

Flowgate owner requests for additional CBM may be submitted at any time for consideration at the next TAWG meeting. The submittal should include written justification and rational for the requested additional CBM. The TAWG shall have authority to reject or grant such requests.

4.4 FLOWGATE AND TFC DETERMINATION

The Flowgates used by SPP to administer the Regional Tariff serve as a proxy of the transmission system. It is therefore essential to the reliable operation of the transmission system for the set of Flowgates to adequately represent the transmission system.

4.4.1 Flowgate Updates

Updating the list of Flowgates is a continual process. Flowgate additions and deletions and changes in TFC are the result of studies, analyses, and operating experience of SPP and its member Transmission Owners. At any time during the year, the owner of transmission facilities may require that a set of facilities be used as a Flowgate to protect equipment or maintain system reliability, regardless of the ownership of that set of facilities. SPP will update the Flowgate list as needed. The responsibility for reviewing and monitoring the list will be shared between the individual Transmission Owners, the TAWG, the Security Working Group (SWG) and the SPP staff. Updating the Flowgate list may or may not require running a study. If the Transmission Owner is to perform a study, they are responsible for gathering accurate information from neighboring Transmission Owners. The following requirements apply when adding a Flowgate to the list:

- Transmission Owners may add OTDF Flowgates, provided that the contingency is valid, the TFC represents the total amount of power that can flow during the contingency without violating the emergency rating of the monitored facility, and no operating procedures apply to that Flowgate.

- Transmission Owners may add PTDF Flowgates, provided that it is a single facility Flowgate, the TFC is equal to the normal rating of the single facility, and no operating procedures apply to that Flowgate.

- All other Flowgates proposed by Transmission Owners must have TAWG and SWG approval. The Security Coordinator can provide interim approval until the TAWG and SWG can convene to assess the request. Examples of such Flowgates are PTDF Flowgates with two or more elements, OTDF Flowgates with three or more elements, or Flowgates involving operating procedures.

There may be times when significant topological changes occur during operations that create unexpected loadings on facilities not explicitly modeled as Flowgates. During these conditions, the Security Coordinator will work with the Transmission Owner(s) to develop a commercial Flowgate representative of the conditions present. Any such additions will be analyzed at the next Flowgate evaluation to determine if they should remain in the permanent list of Flowgates.

4.4.2 Annual Review

In addition to the continual studies and analyses, the Flowgate list will also be reviewed annually by the TAWG using seasonal power flow models. This annual assessment will be performed following the January SPP Model Development Work Group (MDWG) release of each year's load flow cases. This review is intended to serve as a tool by which the TAWG, the Transmission Owners, and the SPP may assess the adequacy of the existing list of Flowgates and thereby recommend necessary additions, deletions, and TFC changes. In order to accomplish this assessment, the process herein described will be used to identify the most limiting elements for a variety of transfer directions. Although transfer values will be involved in this process, this process is not intended to produce any viable ATC values for use commercially or otherwise. Rather, ATC values are determined as described in the "ATC Calculation Procedures" section.

4.4.2.1 Power Flow Models

The power flow models to be used in the process will be based on the models developed annually by the SPP MDWG. Application of the models will use the following season definitions. The Summer Model will apply to June through September, the Fall Model will apply to October and November, the Winter Model will apply to December through March and the Spring Model will apply to April and May. Each of these seasonal models developed will represent peak models. In addition, for the summer season only, a Summer Shoulder Case representing approximately an 85% load level will be used in the determination process.

Prior to the start of the review all SPP Transmission Owners will submit a list of changes to SPP to adjust the models. These changes should be such that the power flow models used to review the Flowgate list represent the seasonal loads, transmission system configuration, generation dispatch, and transactions that each Transmission Owner expects will occur during actual seasonal operations. The changes will be submitted to SPP in a common format as outlined in the SPP Load Flow Procedure Manual.

Model changes and parameters for Transmission Owners outside of SPP will be coordinated through the NERC regional councils.

4.4.2.2 Parameters supplied by the Transmission Owners

In order to simulate a transfer, certain parameters must be known. These include the participation points of MW increase/decrease and the participation factor of these points. These items will be supplied to SPP by the Transmission Owners.

Participation points for exports will primarily be points of generation within the sending area. Generators that are off-line may be turned on to participate in a transfer. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The participation points used for export will be consistent for all transfer directions.

The participation points for imports will primarily be points of generation reduction within the receiving area. A Transmission Owner can specify generators to be excluded from use as participation points, such as generators that serve base load. The generation reduction should be based on economics, operating constraints or other criteria as specified by the Transmission Owner. The participation points used for import will be consistent for all transfer directions.

Other parameters that must be supplied by the Transmission Owners include the following:

- A contingency list including all critical single contingencies (both transmission and generation) as well as multi-terminal facilities.
- All contingencies suspect of causing voltage limitations and the transfers for which they should be studied.
- Any additional facilities below 100 kV to be monitored.
- High and low voltage limits for system and/or individual buses.

- All Contractual Requirements.

4.4.2.3 Default Parameters

The following parameters will be used in the event that a Transmission Owner does not submit the area specific parameters:

- For exports, the participation points will include all on-line generating facilities in the model with unused generating capacity available.
- The export participation factors will be the amount of unused generating capacity at each point divided by the sum of the unused generating capacity at all export participation points.
- For imports, all on-line generators will be decreased prorated by their machine base.
- Transfer directions will be a set of all commercial paths.
- Exports from merchant power plants will be considered in the determination of Flowgates.
- The transfer test levels are specified at the time of the ATC calculations, and are determined by SPP staff.
- All facilities 100 kV and above will be included in the contingency list and the monitored facility list. In addition, the largest unit within the area will be included in the contingency list.
- Voltage limits will be as specified in Planning Criteria section of the SPP Criteria: Regional Transmission Planning.

4.4.2.4 Voltage Limits

Voltage limits are network and system dependent. Each Transmission Owner will submit an acceptable set of Normal Voltage Limits and Emergency Voltage Limits to be applied for the purpose of Flowgate and TFC determination.

4.4.2.5 Linear Analysis and AC Verification

SPP will perform DC linear analysis studies estimating the import or export ability of the identified commercial paths using a combined linear evaluation of the network models with a follow up AC verification of a minimum of the first three valid operational limitations. Specific AC analysis will also be performed on any specified contingency/transfer combinations noted as voltage limiting contingencies. Monitored Facilities, Contingency Facilities and Participation Points will be implemented as described in the “Parameters Supplied by the Transmission Owners” section or “Default Parameters” section as applicable.

4.4.2.6 Operating Procedures

Operating Procedures are available and may increase the Total Flowgate Capacity of a Flowgate when implemented. Implementation of any available Operating Procedures will be done using a full AC solution to determine the correct limit to be placed on a Flowgate. Any operationally increased Total Flowgate Capacities established will be so noted.

4.4.2.7 Identification of Flowgate Changes

TAWG will review the FCITC results of the power flow models and selected paths and identify whether any Flowgates should be added, removed, or changed to better represent the SPP transmission system.

A minimum of the first three valid FCITC limitations to each path will be AC verified. When all paths have been evaluated, the TAWG will review the AC verification results and, where needed, the linear results for consideration as potential Flowgates.

Typically, new Flowgates should be either OTDF Flowgates with a TFC representing the total amount of power that can flow during a contingency without violating the emergency rating of the monitored facility or single facility PTDF Flowgates with a TFC equal to the normal rating of the single facility. In situations involving operating procedures the TFC may be higher than the facility ratings.

The TAWG will then determine any needed changes to the existing list of Flowgates. The number of times elements appear as one of the most limiting components for transfers, the rank in the list of most limiting elements, and the

TDF level will be the primary factors considered in making the determination. Flowgates can also be developed to represent identified Voltage Limitations and Contractual Requirements.

4.4.2.8 Review and Coordination with Transmission Owners

Each SPP Transmission Owner will have the option of naming a representative to review the results of the Flowgate review or deferring to the TAWG finalization of the results. Summary sheets of all interfaces or paths calculated will be communicated to the representatives for review. All data will be made available for review upon request. The results will be approved by the TAWG before being reported.

The Transmission Owner should review the TAWG proposed Flowgate changes and consider their own operating experience and study results. Any modifications to the TAWG proposed changes should be returned to the TAWG. Further dialog and justification may be required of a Transmission Owner if the TAWG has concerns about their modifications.

TAWG will draft a final Flowgate list, incorporating the comments of the Transmission Owners. The Transmission Owners should approve any additions, deletions, or changes to the Flowgate list.

4.4.2.9 Initiating Interim Review Of Flowgate List

Operational condition changes, especially status changes of EHV transmission facilities and large generators, may warrant a partial or full evaluation of the list of Flowgates. A review may also be necessary due to multiple schedules being implemented causing parallel flows.

Transmission Owners will have access to copies of the SPP models and all relevant data used for the annual review. Transmission Owners may at any time request a re-run of the Flowgate evaluations. The Transmission Owner requesting the re-run shall provide their reasons for requesting the re-run to the TAWG for consideration. Should the TAWG deem a re-run necessary, the SPP staff will perform the additional evaluation.

4.4.3 Dispute Resolution

If there is a dispute concerning a Flowgate, the questioning party must contact SPP and the Transmission Owner(s) involved to resolve the dispute.

Examples of reasons for disputing a Flowgate may include:

- The contingency used for the Flowgate is not valid.
- There is an operating procedure that corrects the violation that is not being properly taken into account.
- An operating procedure is being taken into account in an improper manner yielding an incorrect TFC.

If the parties involved do not reach agreement on the selected Flowgates, the SPP TAWG will review all of the arguments. Additional analyses will be performed if necessary. SPP TAWG will then make a final determination. If a party still wishes to dispute the Flowgate, the SPP Dispute Resolution policy described in Section 2 of the SPP By-laws may be initiated.

4.4.4 Coordination with Non-SPP Members

Flowgates involving transfers on interfaces and paths between SPP Transmission Owners and non-SPP Transmission Owners will be coordinated by the parties involved and the TAWG.

4.4.5 Feedback to SPP Members

The SPP staff shall maintain a table of all Flowgates on the SPP OASIS. The table shall include all Flowgate data, which are applicable, including the Flowgate name, monitored facility, contingency facility, Flowgate rating, TRM, CBM, a and b multipliers, LODF, the TDF basis for the Flowgate (OTDF or PTDF), and the TDF cutoff threshold. This table shall be updated with any new information on or before the first of each month.

4.5 ATC CALCULATION PROCEDURES

The determination of ATC via Flowgates utilizes proxy elements to represent the power transmission network. This process depends on the selected Flowgates to act as pre-determined limiting constraints to power transfer. The process by which ATC will be determined when using the Flowgate proxy technique incorporates the Definitions and Concepts within this Criteria.

Determination of ATC via Flowgates adheres to the following approach:

- establishes a network representation (power flow model)
- identifies potential limits to transfer (thermal, voltage, stability, contract)
- determines response factors of identified limits relative to transfer directions (TDF)
- determines impacts of existing commitments (firm, non-firm)
- applies margins (TRM, CBM, a & b multipliers)
- determines maximum transfer capabilities allowed by limits and applied margins (ATC, FATC, NFATC)

4.5.1 ATC Calculation and Posting Timeframes

To assist Transmission Providers with Short Term service obligations under FERC Order 888 and 889, SPP will calculate the monthly path ATC for the upcoming 16-months for all potential commercial paths for Transmission Providers in the SPP Region. This data will be posted for use in evaluating the SPP OATT requests and provided on a monthly basis to the Transmission Providers in adequate time to post the information on OASIS nodes by the 1st of each month.

Hourly, Daily and Weekly ATC shall be calculated on a daily basis and posted at the time of run. SPP will also provide commercial path conversions to any individual providers needing that information to administer their own tariff. Hourly ATC shall be calculated for 12 to 36 hours ahead depending on time of day. SPP has a firm scheduling deadline at 12:00 noon of the day prior to start. At this point all firm schedules are known and the hourly non-firm request window opens for the next day. At this point SPP will calculate hourly ATC for HE 14 of the current day through HE 24 of the next day. This process continues dropping the current hour each resynchronization until 12:00 noon the next day when the cycle starts again. Again SPP will provide commercial path conversions for any SPP provider that needs them for posting on their own OASIS nodes.

4.5.2 Power Flow Models

The monthly calculation of Flowgate based ATC will be made using rolling seasonal models that produce an update for the upcoming sixteen month service window (12 month multi-month service + 4 months advance notice). For example, the required data update for January of any year will yield data for January thru December plus the next January, February, March and April of the following year. The necessary seasonal models will be selected from the approved SPP MDWG set to represent this time frame. Any known system changes/corrections to these models will be included. SPP will routinely calculate ATC for the upcoming 16-month service window. Monthly models will be updated/developed from the latest seasonal models to represent individual months for the purpose of capturing operational conditions that may be unique from other monthly models.

4.5.3 Base Loading , Firm and Non-Firm (FBL & NFBL)

Model base flows provide the basis for which to begin determination of Available Flowgate Capacity. However, there are many transactions within the monthly models that are duplicated on the OASIS. A record of the network model flows of each Flowgate as found in the solved network models will be used as a beginning point to account for impacts of base case transactions and existing commitments. The impacts on Flowgates due to transactions outside the purpose of representing designated Network Resource exchange will be removed by applying the TDF factors determined to each transaction identified in the base case. In addition to adjusting the model flow in this manner, positive and counter impacts of existing OASIS commitments will be applied according to the type of Base Loading (Firm or Non-Firm) under consideration. In non-firm Base Loading, 50% of Counter Impacts resulting from firm Confirmed reservations will act to reduce the overall Base Loading figure. This process will establish the base loading expected with each control area serving its firm Network Load.

4.5.4 Transfer Distribution Factor Determinations (TDF)

Participation data provided by Transmission Owners from the annual Flowgate evaluation process will be used as default data unless otherwise specified. TDF data will be calculated for all commercial paths using the most current participation data, ATC models and Flowgate list on a monthly basis.

4.5.5 Existing Commitments and Netting Practices

Existing commitments resulting from Confirmed, Accepted and Study reservations on the SPP OATT OASIS nodes will be considered and accounted for in the determination of Available Flowgate Capacity. Accounting for the impact of existing commitments is a key part of the process for determining which new transfers will be allowed, unlike the TLR implementation process which involves determining which existing transfers must be curtailed. Therefore, unlike TLR implementation which requires a minimum TDF threshold, all positive impacts from existing commitments must be applied without using a minimum TDF threshold. Impacts from these commitments will be applied according to the future time frame of which they are applicable. These time frames are discussed below:

4.5.5.1 Yearly Calculations (whole years, starting 60 days out)

A Yearly transmission service request is defined as a service request with a duration of greater than or equal to 1 year in length. The evaluation of Available Transfer Capability for this service type is performed utilizing solved network models with existing OASIS commitments figured in as net area interchange values. In addition to monitoring Flowgates, standard N-1 contingency analyses will be performed to study the impact of yearly transmission requests on the transmission system.

4.5.5.2 Monthly Calculations (months 2 through 16)

The impacts of OASIS reservations that are Confirmed, Accepted and in Study mode will be applied to each Flowgate according to the TDF values determined. All positive impacts on a Flowgate due to these types of reservations decrease ATC. 100% of counter flow impacts due to reservations supplying Designated Network Resources are allowed to increase ATC. For non-firm service, up to 50% of the counter-flows due to all firm Confirmed reservations will be allowed on a Flowgate. The combined positive impacts and counter flow impacts will be added to the base flows to determine Available Flowgate Capacity for the Monthly calculation.

4.5.5.3 Daily and Weekly Calculations (Day 2 through 31)

For Daily and Weekly calculations, composite area interchange values will be determined by integrating all OASIS Confirmed and Accepted reservations into projection models. Base flows will be determined by the projection models and counter flow impacts will be backed out by applying the necessary negative TDF calculations to all Accepted, Confirmed and Study reservations. For non-firm Available Flowgate Capacity calculations, up to 50% of the counter flow impacts due to all firm Confirmed reservations will be allowed. For firm Available Flowgate Capacity, the counter flow impacts of Confirmed reservations for Designated Network Resources are allowed to unload Flowgates.

4.5.5.4 Hourly Calculations (Day 1)

These calculations are for hourly non-firm service only. All known schedule information from NERC Electronic-tags will be applied to base flow calculations. These schedules determine base interchange values. Since these are expected schedules, all counter flow impacts are allowed in this calculation. OASIS reservation information is not considered for determination of existing impacts in this calculation.

4.5.6 Partial Path Reservations

Requests made on individual Transmission Provider's tariffs require two or more reservations to complete a transaction resulting in a partial path reservation. The SPP OATT offers service out of, into and across SPP and between SPP members with a single reservation. For transmission service under the SPP OATT, only reservations with valid sources and sinks are allowed. However, to avoid double accounting of Flowgate and system impacts due to duplicate reservations documented on Transmission Provider OATT OASIS nodes from partial path reservations, necessary means will be incorporated to recognize these related reservations and determine the correct singular impacts.

4.5.7 ATC Adjustments Between Calculations

ATC will be adjusted following receipt of any valid SPP OASIS node reservation. The requested capacity will be multiplied by the TDF on all affected Flowgates and the resulting amounts will be subtracted from each Flowgates' ATC and posted to the OASIS.

4.5.8 Coordination of Transmission Commitments with Neighboring Organizations

Coordination of dispatch information, Confirmed firm and non-firm system commitments from neighboring regions, RTO's, ISO's etc. will be conducted as appropriate to each type of ATC being determined to establish the most accurate system representation of base flows and generation profiles. External reservations may be retrieved from other OASIS sites or locations designated by neighboring Transmission Providers.

4.5.9 Margins

Identified TRM and CBM will be applied to each Flowgate as described in the Reliability Margins section.

4.5.10 ATC Determination

The following equations are used in ATC determination:

4.5.10.1 Firm Base Loading (FBL)*, **:

- Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm OASIS Commitments, Confirmed, Accepted and Study) – (100% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments for DNR only)

4.5.10.2 Non-Firm Base Loading (NFBL)*, **:

- Non-Firm Base Loading = (Flows resultant of DNR) + (Σ Positive Impacts due to Firm and Non-Firm OASIS Commitments, Confirmed, Accepted and Study) – (up to 50% of Σ Counter Impacts due to Confirmed Firm OASIS Commitments)

4.5.10.3 Firm Available Flowgate Capacity (FAFC):

- Firm Available Flowgate Capacity = (Total Flowgate Capacity) – (TRM) – (CBM) – (Firm Base Loading)

4.5.10.4 Non-Firm Available Flowgate Capacity (NFAFC, Operating Horizon):

- Non-Firm Available Flowgate Capacity, Operating Horizon = (Total Flowgate Capacity) – (b*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.5 Non-Firm Available Flowgate Capacity (NFAFC, Planning Horizon):

- Non-Firm Available Flowgate Capacity, Planning Horizon = (Total Flowgate Capacity) – (a*TRM) – (CBM) – (Non-Firm Base Loading)

4.5.10.6 Firm Available Transfer Capability (FATC):

- Firm ATC = Most limiting value from associated Flowgates = Min {Firm Available Flowgate Capacity/TDF of appropriate path}

4.5.10.7 Non-Firm Path Available Transfer Capability (NATC, Operating Horizon):

- Non-Firm ATC, Operating Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Operating Horizon/TDF of appropriate path}

4.5.10.8 Non-Firm Available Transfer Capability (NFATC, Planning Horizon):

- Non-Firm ATC, Planning Horizon = Most limiting value from associated Flowgates = Min {Non-Firm Available Flowgate Capacity, Planning Horizon/TDF of appropriate path}

* Applicable pre-emption requirements of lower priority service types will be considered when evaluating requests for transmission service.

** Impacts resulting from queued Study reservations will be applied according to priority when evaluating requests for transmission service.

SPP will calculate the ATC for each of its Transmission Providers on their direct interconnections (either physical interconnections or by rights to a line) and any interface or path requested by a Transmission Provider to fulfill its obligations under FERC Order 889. The ATC for requested interfaces or paths will be calculated only if requested by the Transmission Provider obligated to post the interfaces or paths.

4.5.11 Annual Review of ATC Process

The SPP TAWG will conduct an annual review of the Regional ATC determination process including TRM and CBM to assess regional compliance with NERC requirements, regional reliability needs and functionality toward SPP Transmission Owners and Users. This review will be held at the same time as the Flowgate Evaluation process.

SPP will conduct a survey of the Transmission Owners and Users and the results will be published on the SPP website. Concerns that are identified from the survey will be forwarded to the appropriate SPP Committee.

4.5.12 Dialog With Transmission Users

Transmission Users may contact the TAWG with any concerns regarding this criterion, its implementation, or the resulting ATC values. The concerns should be in writing and sent to the chair of the TAWG. The chair will then draft a written response to the Transmission User containing either an answer or a schedule for when such an answer can be provided. If the Transmission User is not satisfied, the concerns can be sent to the chair of the Engineering and Operating Committee.

Southwest Power Pool
ENGINEERING AND OPERATING COMMITTEE
Recommendation to the Board of Directors
December 11-12, 2001

MODIFICATION OF SPP CRITERIA, SECTION 5.2.4.1

Background

During their September 1, 2000 conference call, the Security Working Group (SWG) approved several changes to SPP Criteria 5 and added Appendix 7 to the Criteria. At their November 6, 2000 meeting, the SPP Board of Directors (BOD) pointed out an inconsistency in the SPP Criteria during their review of those recommended revisions to SPP Criteria 5. Specifically, a sentence remained in Section 5.2.4.1 that referenced data collection on a ten-minute cycle.

Recent Activity

SPP staff reviewed the revisions to SPP Criteria 5 and Appendix 7 and made a recommendation to the SWG at their April 17-18 meeting to rewrite a sentence in Section 5.2.4.1 containing the inconsistency observed by the BOD. The SWG approved this recommendation as submitted.

Analysis

Current Wording of Section 5.2.4.1 item a.

a. Monitor the collection of operating information from control areas on a ten minute cycle, including load, area interchange error, scheduled transactions, interconnection real and reactive power flows, status of all transmission facilities at 115 kV and above plus selected 69 kV facilities, and generator real and reactive output, ready and spinning operating reserve, minimum and maximum unit output constraints, and voltage.

As documented in the newly created Appendix 7, collection periodicities are specifically stated for each of the different types of data. Most of the data that was previously defined as collected on a 10 minute periodicity was changed to a minimum of a 30 second periodicity in the last revision of the SPP Criteria. Therefore, the reference to data collection on a 10-minute cycle should be removed from Section 5.2.4.1 since the periodicities are stated in Appendix 7.

In addition to the recommendation to remove the reference to a 10-minute cycle, the SPP staff noted that the entire sentence regarding the monitoring of data collection was stating specific types of data. These specific data point descriptions are now listed in Appendix 7. Therefore, it is the recommendation of the SPP staff to remove specific references to the types of data to be collected from Section 5.2.4.1. The reference for voltage specific data should also be removed since Section 5.1 of the Criteria states that data from facilities operated at 60 kV and above shall be automatically shared.
As a final documentation change, Appendix 7 should be added to the Index.

Recommendation

The SWG recommends that the proposed wording be incorporated into SPP Criteria, Section 5.2.4.1. Proposed Wording of Section 5.2.4.1 item a.

a. Monitor the collection of real-time operating information, schedules and daily forecasts from control areas as specified in Appendix 7.

Approved

Security Working Group	April 2001
Engineering and Operating Committee	October 2001

Action Requested

The Board of Directors is requested to approve the changes listed above to the SPP Criteria, Section 5.2.4.1 as recommended by the EOC.

Southwest Power Pool
ENGINEERING AND OPERATING COMMITTEE
Recommendation to the Board of Directors
December 11-12, 2001

MODIFICATION OF SPP CRITERIA, SECTION 7.3.1.3 a

Background

At the last EOC meeting, the SPCWG presented updated SPP Criteria 7.3 to be approved. There was a discussion on how to interpret the three steps involved in the Under Frequency Load Shedding Plan. The EOC decided to send the Criteria back to the SPCWG to be rewritten in a clear and precise manner, so there is no confusion as how the steps are to be interpreted. Ron Ciesiel and Scott Moore were put in charge of working with the SPCWG and SWG to clear up the wording for Criteria 7.3.

Recent Activity

The SPP Criteria section 7.3.1.3 a. was rewritten to clarify the three Under Frequency Load Shedding steps. Ron Ciesiel sent out the rewording to the chairmen of the SWG, SPCWG, MDWG and other involved members.

Analysis

The rewording of SPP Criteria 7.3.1.3.a. should eliminate any confusion on the size of each step. Each step is to be 10% of the total member load at the time of the event or simulation. After all three steps have been taken, the load shed shall be 30% or greater of the initial load.

The Criteria that was presented at the March EOC meeting is submitted along with the rewritten Criteria as an attachment.

Recommendation

The Chairmen of the SWG, SPCWG, and the MDWG have approved the rewording of the Criteria. They recommend the proposed wording to be incorporated into SPP Criteria Section 7.3.1.3 a.

Approved

The Criteria changes have been approved by the Chairmen of the SWG,SPCWG, and MDWG.

Action Requested

The Board of Directors is requested to approve the changes listed above to the SPP Criteria, Section 7.3.1.3 a. as recommended by the SWG, SPCWG, and MDWG and EOC.

SPP Criteria 7.3.1.3 that was submitted at the March EOC meeting

7.3.1.3 Implementation

a. Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated in steps as indicated below. Each member's underfrequency load shedding (UFLS) schemes shall have the capability to shed its load in a minimum of ten (10) percent increments for a total of not less than thirty (30) percent of the load at summer peak after all three (3) steps of load shedding occur. Only the non-intentional delays including operating times of relays and breakers, plus any intentional delay as allowed in Criteria 7.3, shall delay the interruption of pre-event load for all events at the time of each event. All UFLS schemes shall be in service to trip loads except for maintenance and testing purposes.

Frequency (Hz)	Step	Minimum Load Relief (%)
59.3	1	10
59.0	2	10
58.7	3	10

Proposed wording for section 7.3.1.3

7.3.1.3 Implementation

a. Should the utilization of spinning reserve fail to stop a frequency decline, load shedding shall be initiated in steps as indicated below. The goal of the program is to prevent a cascading outage due to a frequency excursion and restore the system to a stable condition. Members must be ready to shed, in three steps, thirty (30) percent of a member's current load regardless of the starting load point (i.e. peak-load, shoulder-load, low-load). This requirement shall be achieved as follows: 1) A member may dynamically arm and disarm UFLS relays to achieve the required load shedding totals, indicated in the chart below, by utilizing a load following program. For the purposes of this section, the term 'dynamically' means that no operator intervention is required to arm or disarm a UFLS relay, **or** 2) A member that does not dynamically arm and disarm UFLS relays shall install, or have installed on its behalf, UFLS relays with a total capability of shedding a minimum of thirty (30) percent of the member's projected summer peak load. The relays shall be set to shed the thirty (30) percent total in increments of projected peak load per step, as indicated in the chart below. Once installed, these UFLS relays shall remain in service to trip loads except for periods of testing and maintenance.

   Regardless of the technique utilized only the non-intentional delays including operating times of relays and breakers, plus any intentional delay as allowed in Criteria 7.3, shall delay the interruption of pre-event load for all events at the time of each event.

Step	Frequency (hz)	Minimum Load Relief (%)
1	59.3	10
2	59.0	10
3	58.7	10

Southwest Power Pool
ENGINEERING AND OPERATING COMMITTEE
Recommendation to the Board of Directors
December 11-12, 2001

REVISIONS TO SPP CRITERIA 9.0

Background
System restoration in the event of a black out scenario requires thorough plans in place by each Control Area and Regional Council. During the April 28, 2000 conference call, the Security Working Group (SWG) formed the Black Start Study Task Force (BSSTF) to gather and review each SPP Control Area's Black Start Plan and verify that each plan is comprehensive and operationally sound.

Recent Activity
Recent changes in NERC Criteria require each Regional Council to establish, maintain, and verify a system Black Start Plan. During the February 21-22, 2001 meeting, the SWG charged the BSSTF to assemble a Black Start Plan for the SPP region adhering to NERC Criteria, update SPP Criteria 9.0, and develop synchronization guidelines. The BSSTF offered synchronization guidelines, an outline for the regional black start plan, and draft changes to SPP Criteria 9.0 at the June 6-7, 2001 SWG meeting. The SWG offered feedback to the draft changes and the BSSTF presented the final set of revisions to Criteria 9.0 at the August 27-28, 2001 SWG meeting. The SWG suggested minor changes before submitting a recommendation to the EOC at the September 17-18, 2001 meeting.

Analysis
The BSSTF reviewed existing SPP Criteria and member Black Start plans to identify deficiencies and update Criteria 9.0 to assist expeditious regional system restoration in adherence with NERC Criteria. The role of the SPP Security Coordinator was expanded from an information coordinator to an active role in coordinating and assisting in the recovery efforts, including the authority to suspend normal market operations and to recommend sharing of generation resources between Control Area members.

Member Black Start plans were in need of synchronization guidelines and this reference was added to the required elements for member Black Start plans.

Conclusion
The SWG reviewed the synchronization guidelines and draft changes to Criteria 9.0 and offered minor suggestions to these submittals. The SWG concluded that the synchronization guidelines should be included in the Regional Black Start Plan and should not be included in SPP Criteria. The BSSTF has incorporated the suggestions of the SWG for Criteria 9.0 including expanding the role of the SPP Security Coordinator.

REVISIONS TO SPP CRITERIA 9.0

Recommendation
The EOC recommends the attached revisions be incorporated into SPP Criteria 9.0.

Approved

Black Start Study Task Force	August 2001
Security Working Group	August 2001
Engineering and Operating Committee	October 2001

Action Requested
The Board of Directors is requested to approve the attached revisions to SPP Criteria 9.0 as recommended by the EOC.

Attachments

1. Criteria 9.0

Southwest Power Pool Criteria

9.0 BLACK START

This document provides general guidelines to be followed in the event of a partial or complete collapse of the SPP bulk electric system. For more detailed information please refer to the SPP regional black start plan. Quick implementation of each Control Area's restoration plan compiled according to this Criteria shall facilitate coordination between member Control Areas and the SPP Security Coordinator ~~Office~~ and insure the earliest possible restoration of the electric
~~s~~system. It is impossible to predict all the possible combinations of system problems which may occur after a major electric system failure. It is therefore the responsibility of system operators to restore the electric system applying the general guidelines outlined in this document and in their respective detailed black start plans. Strict adherence to other SPP Criteria is also necessary for a prompt restoration of the electric system. Mutual assistance between member Control Areas is highly encouraged. This assistance may include the sharing of black start units. The SPP Security Coordinator ~~Office~~ shall take an active role ~~act only as an information coordinator~~ during electric system restoration as outlined in this Criteria. Each Control Area shall have a readily accessible and sufficiently detailed, current restoration plan to assist in an orderly restoration. Restoration shall be aided by communicating to neighboring Control Areas and the SPP Security Coordinator ~~Office~~ an accurate assessment of the
network conditions throughout the restoration process. Communication shall be established between neighboring operation centers, power plants and the SPP. ~~Office.~~ Mutual assistance and cooperation are essential during restoration activities to avoid reoccurrence of a partial or complete electric system collapse.

9.1 Responsibilities

9.1.1 Members

Each member Control Area shall develop and maintain a detailed internal black start plan and train associated personnel (system operators, power plant operators, etc.) in its implementation. Non-Control Area members shall prepare a plan in cooperation with their responsible Control Area designed to assist and coordinate with the Control Area's plan. This applies to cogeneration facilities and independent power producers. A copy of this plan shall be on file at the SPP
~~O~~office. Black start plans shall be verified by a minimum of simulation testing, although actual physical testing is highly encouraged where feasible. Members shall report any testing activities of black start plans to the Operating Subcommittee.

~~All energy tagging and normal energy scheduling practices may be ignored in the event of a total system collapse. Generation may be shared on a pro-rata basis between control areas until the following conditions are met as determined by the SPP as Security Coordinator:~~

~~At least 75% of the load in the SPP region has been restored or~~
~~At least 75% of the load in a control area has been restored and~~
~~A period of 12 hours has elapsed since the blackout occurred~~

In the event of an electric system collapse, each member Control Area shall use the following items as guiding principles for the restoration process.

a. Provide assistance to any and all SPP members as abilities allow, with priority given to the restoration of inter-system bulk electric system ties.

b. Take immediate steps to initiate internal restoration plans.
c. Supply neighboring Control Areas and the SPP Security Coordinator ~~Office~~ with information on network status.
d. Coordinate with neighbors the re-connection of Control Areas and/or islands,
e. If it becomes apparent that the emergency is of regional magnitude, the focus of restoration action shall shift from individual Control Area priorities to bulk network priorities. Priority to a neighboring member's load may be necessary in order to benefit the overall strength of the bulk electric system. As generation and transmission facilities become available, systematic restoration of network load shall be initiated with respect to priorities.
f. Generation should be made available to all regional utilities for system and customer load restoration as recommended by the SPP Security Coordinator.

9.1.2 SPP Security Coordinator ~~Office~~

The SPP Security Coordinator ~~Office~~ shall be familiar~~ize associated personnel~~ with each Control Area's black start plan which is on file. In the event of a failure of the bulk electric system, the SPP Security Coordinator ~~Office~~ personnel shall take the following action.

a. The SPP Security Coordinator has the authority to temporarily suspend ~~energy tagging and~~ normal energy scheduling practices.
b. The SPP Security Coordinator should recommend sharing of generation available to all regional utilities for system and customer load restoration.
c~~a~~. Maintain continuous surveillance of the status of the networks of all member Control Areas (refer to section 9.4 for information required).
d~~b~~. Act as a central information collection and dissemination point for members.
e~~c~~. Communicate with other regional offices, NERC and the Federal Emergency Management Administration.
f~~d~~. Communicate/recommend the need for assistance to appropriate members.
g~~e~~. ~~If requested, t~~The SPP Security Coordinator ~~Office~~ shall assist Control Areas in a coordinated restoration by monitoring implementation of plans, by providing status information to appropriate Control Areas, and by facilitating assistance and re-connection.
h~~f~~. The SPP Security Coordinator ~~Office~~ shall expect notification of Control Area status from the members. It is necessary that this information be recorded and shared with all members. Based on this information, the SPP Security Coordinator ~~Office~~ shall immediately assess electric system conditions and status of communication facilities and inform all Control Areas of the extent of the blackout (refer to section 9.4 for information required)..

9.2 Elements of Member Black Start Plans

Each member shall maintain a black start plan that is consistent with this Criteria. All plans and procedures shall be readily available to system operators, plant operators and the SPP Office. System operators shall review these documents on a regular basis. It is suggested that member black start plans include the following elements.

a. Philosophies and strategies for Control Area restart.
b. Identification of the relationships and responsibilities of the personnel necessary to the restoration.
c. Identification of black start resources including generating unit resources, sufficient fuel resources, transmission ~~resources~~corridors or paths, communication resources and power supplies, mutual assistance arrangements.
d. Contingency plans for failed resources.
e. Identification of critical load requirements.

f. Identification of special equipment requirements.
g. Provisions for training of personnel.
h. Provisions for simulating and where practical, actual testing and verification of the resources and procedures.
i. General instructions and guidelines for system operators, plant operators, communications personnel, and transmission and distribution personnel.
j. Provisions for public information.
k. Synchronization Guidelines

~~The~~ Appendix 4 contains a list of items to be considered in the restoration process which may be used in the development or review of black start plans.

9.3 Restoration Priorities

The following actions for system restoration shall be considered by each Control Area and assigned proper sequence and priority.

a. Stabilization of generating units.
b. Restoration of inter-system and intra-system bulk electric system ties.
c. Restoration and maintenance of intra- and inter-system communication facilities and networks.
d. Assessment of Control Area condition and SPP electric system condition.
e. Contact with public information agencies (Emergency Broadcasting System) to request the broadcasting of pre-distributed appeals and instructions.
f. Restoration of units with black start capability.
g. Providing service to critical electric system facilities.
h. Connection of islands taking care to avoid reoccurrence of a partial or complete system collapse and equipment damage.
i. Restoration of service to critical customer loads.
j. Restore service to the remaining customers.

9.4 Information Communication

Reliable communication between the members and SPP Security Coordinator ~~Office~~ will be the key to a safe and timely restoration following a collapse of the SPP network. As part of the initial assessment after a partial or complete system blackout, communication facilities shall be tested and verified. System operators shall establish communication within their area with special emphasis given to power plants and neighboring members. ~~Should problems be encountered with any primary communication facilities~~To expedite the recovery process, the SPP Emergency Communication Network (satellite phones) shall be used to convey ~~the~~ appropriate information to members. ~~Communication is vital to an orderly recovery~~. **Control Areas are to be prepared to communicate their status once an hour and will be polled by SPP Security Coordinators ~~Operators~~ or whenever any significant change occurs**. Only after voice communication paths have been established shall efforts be directed to re-establishing data communication paths. System status conditions to be surveyed include but are not limited to the following items.

a. Areas of the electric system which are de-energized,
b. Areas of the electric system which are functioning,

c. Amount of generation and generating reserve available in functioning areas,
d. Power plant availability and time required to restart,
e. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants,
f. Status of transmission breakers and sectionalizing equipment at tie points to other areas,
g. Status of fuel supply from external suppliers,
h. Under-frequency relay operation,
i. Relay flags associated with circuits tripped by protective relays.
j. Status of communication systems

Southwest Power Pool
ENGINEERING AND OPERATING COMMITTEE
Recommendation to the Board of Directors
December 11-12, 2001

REVISIONS TO SPP CRITERIA 10.0

Background

Dependable communication between members and SPP, especially in a partial or complete blackout is critical for system restoration. During the April 28, 2000 conference call, the Security Working Group (SWG) formed the Black Start Study Task Force (BSSTF) to gather and review each SPP Control Area's Black Start Plan and verify that each plan is comprehensive and operationally sound.

Recent Activity

Recent changes in NERC Criteria require each Regional Council to establish, maintain, and verify a system Black Start Plan. During the February 21-22, 2001 meeting, the SWG charged the BSSTF to assemble a Black Start Plan for the SPP region adhering to NERC Criteria, update SPP Criteria 10.0, and develop synchronization guidelines. The BSSTF offered synchronization guidelines, an outline for the regional black start plan, and draft changes to SPP Criteria 10.0 at the June 6-7, 2001 SWG meeting. The SWG offered feedback to the draft changes. The BSSTF made the recommended changes and presented these to the SWG at the August 27-28, 2001 meeting. The SWG suggested minor changes before submitting a recommendation to the EOC at the September 17-18, 2001 meeting.

Analysis

The BSSTF reviewed existing SPP Criteria to identify deficiencies and update Criteria 10.0 to assist expeditious regional system restoration in adherence with NERC Criteria. Minor clarifications were added regarding communication with generating stations and the testing of the SPP emergency communications system. Criteria 10 references Appendix 3 and this Appendix required replacement of the emergency radio instructions with instructions and procedures for the emergency satellite phone system.

Conclusion

The SWG reviewed the draft changes to Criteria 10.0 and offered minor suggestions to this submittal. The BSSTF has incorporated the suggestions of the SWG for Criteria 10.0.

Recommendation

The EOC recommends that the attached revisions be incorporated into SPP Criteria 10.0 and Appendix 3.

REVISIONS TO SPP CRITERIA 10.0

Approved

Black Start Study Task Force	August 2001
Security Working Group	August 2001
Engineering and Operating Committee	October 2001

Action Requested

The Board of Directors is requested to approve the attached revisions to SPP Criteria 10.0 and Appendix 3 as recommended by the EOC.

Attachments

1. Criteria 10.0
2. Appendix 3

10.0 EMERGENCY COMMUNICATION

Dependable communication between members is critical to maintaining a reliable bulk electric system. As part of the initial assessment following a network disturbance or after a partial or complete blackout, communication facilities shall be tested and verified. Control Area ~~System~~ operators shall establish communication with neighboring members and the SPP~~.~~ Security Coordinator. Control area operators shall establish contact with power stations.

10.1 SPP Emergency Communication Network

Should problems be encountered with any primary communication facilities, the SPP Emergency Communication Network shall be used to convey the appropriate information. Communication is vital to an orderly recovery. Priority should be given to establishing voice communication paths prior to re-establishing data communication paths. The SPP Emergency Communication Network is comprised of Satellite Phones located at each Control Area operating center. General i~~I~~nformation ~~needed for the configuration~~ and operational instructions for ~~of~~ these phones is contained in ~~the~~ Appendix 3. During emergency conditions requiring the use of the SPP Emergency Communication Network, the Security Coordinator shall initiate a Group Call and quickly determine the extent of the interruption. Operating personnel shall keep conversations concise to keep channels clear. It is important in emergency situations for system operators to be familiar and comfortable with the phone operation. Each Control Area shall ~~particpate~~participate in the weekly test ~~institute a practice~~ of the ~~utilizing the~~ SPP E~~e~~mergency Communication Network. Each Control Area system operator and the SPP Security Coordinator ~~- operator~~ should become familiar with the operation of the phone. ~~by using it for some standard communication need between neighbors. no less than once a month.~~ The Security Coordinator shall instigate and monitor this testing and training process.

10.2 Information Priority During Emergencies

System status conditions to be surveyed include but are not limited to the following items:

a. Areas of the electric system which are de-energized,
b. Areas of the electric system which are functioning,
c. Amount of generation and generating reserve available in functioning areas,
d. Power plant availability and time required to restart,
e. Status of transmission breakers and sectionalizing equipment along critical transmission corridors, and at power plants,
f. Status of transmission breakers and sectionalizing equipment at tie points to other areas,
g. Status of fuel supply from external suppliers,
h. Under-frequency relay operation,
i. Relay flags associated with circuits tripped by protective relays.
j. Status of communication systems.

Southwest Power Pool
Finance Working Group Recommendation
To the Board of Directors
December 12, 2001

2002 Budget

Background

On November 16, 2001 the Finance Working Group chaired by Trudy Harper and consisting of Dick Dixon, Gene Argo, Jim Eckelberger, Harry Skilton and John Marschewski met by conference call to review the SPP 2002 proposed budget prepared by the staff. After review the Finance Working Group recommends approval of the 2002 Administrative Budget of $28,488,785. Summary pages of that Budget review are attached. Ms. Trudy Harper, interim chair of the Finance Working Group, will present the 2002 Southwest Power Pool Administrative Budget for Board approval.

The recommended 2002 budget is approximately $8,553,000 over the 2001 budget. The Executive Summary details the reasons for these cost increases. Two new items account for the substantial increase in budgeted expenses: market operations outsourcing contract with Accenture and ESCA software maintenance contract. Staff has estimated income through the transaction fee associated with the regional tariff to be $7,500,000 in 2002.

This proposed 2002 administrative budget excludes several items staff believes will be required if SPP is to perform the functions required of a RTO. Significant among these items is the development and implementation of a congestion management system. Staff estimates total additional costs required in 2002 to support RTO operations will be $5,700,000 (includes staffing, capital expenditures, legal costs, etc.).

Recommendation

The Finance Working Group recommends the approval of the 2002 SPP Administrative Budget of $28,488,785.

Approved: Finance Working Group 11/16/01

Action Requested: Approve Recommendation

2002 PROPOSED ADMINISTRATIVE BUDGET
EXECUTIVE SUMMARY

The proposed 2002 administrative budget is $28.5 million with a net increase of approximately $8.5 million over the 2001 budget. The 2002 budget reflects tariff income of $7,500,000, which will not meet 80% of the expenses, therefore resulting in an estimated shortfall for 2002 of $15.3 million. Two new items account for the substantial increase in budgeted expenses: market operations outsourcing contract with Accenture and Esca software maintenance contract. These items are discussed below and in the body of the budget.

SPP's proposed 2002 administrative budget excludes several items staff believes will be required if SPP is to perform the functions required of a RTO. Significant among these items is the development and implementation of a congestion management system. Staff estimates total additional costs required in 2002 to support RTO operations will be $5,700,000 (includes staffing, capital expenditures, legal costs, etc.).

Significant budget increases/decreases from the 2001 budget are shown below.

Category 1 - SALARY/EMPLOYEE BENEFITS
($3,085,000 Increase; for a 2002 total of $14,020,000)

Additional Employees – Staff is recommending three new full time employees and justifications for these additions are included in Category 1 detail. The President supports these additions. ($134,000), a full year with all three positions will be $171,000)

Compensation Adjustment – The Employee Benefits Working Group reviewed compensation levels for SPP Staff, made a recommendation to the Board of Directors, which was approved, for a 4.5% salary adjustment, excluding the President. ($433,000 increase over current salary levels)

Employee Benefits WG Incentive Packages – The Employee Benefits Working Group developed an incentive and retention program for SPP Staff which was approved by the Board of Directors. ($1,142,000)

Welfare Benefits – This line item increased substantially in 2001 due to additional staff and increases in healthcare benefit premiums. We anticipate continued growth in this component during 2002. ($727,000)

Pension Funding - Additional funding is necessary to maintain the financial integrity of the plan. ($100,000)

Category 2 - EMPLOYEE TRAVEL EXPENSES
($79,000 Increase; for a 2002 total of $593,500)

The increase is for the anticipated travel expenses for additional staff responsibilities.

Category 3 - ADMINISTRATIVE
($290,400 Increase; for a 2002 total of $726,400)

Energy usage – Electric utility expense will increase due to the addition of new computer hardware and systems and the necessary heating and cooling needed to ensure its maximum performance. ($50,000)

Insurance – Premium increases are expected due to increased coverage levels for Directors and Officers coverage and excess liability insurance. Additionally, the 2002 budget includes an estimated premium for credit insurance (originally purchased (unbudgeted) in 2001). ($230,000)

Category 4 - NERC ASSESSMENT
($300,000 Decrease; for a 2002 total of $900,000)

Category 5 - SPP/NERC MEETINGS
($10,000 Increase; for a 2002 total of $232,000)

Category 6 - COMMUNICATIONS
($580,000 Increase; for a 2002 total of $1,396,000)

SPPNET – Continued upgrade of the frame relay network and attached routers required to meet the current needs of the members. Upgraded routers will result in increased security, decreased failure rates, support the increased bandwidth requirements of the scheduling system, and reduce maintenance costs. ($300,000)

Redundant SPPNET - The implementation of a redundant SPPNET will provide full redundancy (no single point of failure) at SPP and depending on how the local loops are installed, there would be full redundancy of circuits and hardware at the member sites. ($175,000)

Category 7 - CAPITAL / OPERATING LEASES AND MAINTENANCE
($1,500,000 Increase; for a 2002 total of 4,087,000)

ESCA Software Maintenance - Expenditures cover the standard Alstom ESCA maintenance agreement that provides basic support during normal business hours with no service level criteria. ($1,500,000)

Category 8 – CAPITAL EXPENDITURES
($934,000 Decrease; for a 2002 total of $2,023,000)

Redundant SPPNET Hardware – Operation of the SPP market systems requires maximum availability of telecommunications. Redundancy is required to insure constant access and flow of information between SPP and the membership(bi-directional exchange of real time data). ($320,000)

Redundancy / Emergency Backup Site - The SPP Security Working Group authorized the development of an emergency backup site. While it was intended that this project would be completed in 2001, the demands placed on the SPP staff by the EMS upgrade and COS/MOS project precluded the assignment of resources to this task. ($527,000)

Furniture - Replace older modular furniture, plus furnishing the SPP training center. ($290,000)

Personal Computers - PC replacements are on-going to ensure that employees are furnished with necessary equipment to effectively perform their duties. ($180,000)

Intrusion Detection System - With the steady increase in internet based viruses, worms, and general hacking attempts, it is critical that SPP acquire and install a good intrusion detection system as part of its protection scheme. ($100,000)

Category 9 - OUTSIDE SERVICES
($4,009,000 Increase; for a 2002 total of $6,081,000)

Accenture Consulting – On August 30, 2000, the Board of Directors approved the letting of a five-year contract with Accenture for the design and operation of the market settlement system. The approval was on a present value cost amount, which included outsourcing operations of the financial settlement system to Accenture. ($4,000,000)

Category 10 - MISCELLANEOUS INCOME
($223,000 Decrease; for a 2002 total of $1,570,000)

SPP AEP/Ohio Agreement – The agreement is expected to terminate December 2001 resulting in a reduction in reimbursement income. ($720,000)

SPPNET Reimbursement – Reimbursement by members of SPPNET and Redundant SPPNET upgrades. ($530,000)

Category 11 - TARIFF INCOME
($1,290,000 increase; for a 2002 total of $7,500,000)

Tariff income of $7.5 million is expected to be $1.3 million more than budgeted for 2001. Most of the excess is attributed to unbudgeted network service. There was also an increase in the yearly firm transmission service due to expiring grandfathered service. No significant increase is expected for 2002 over the projected 2001 level, as the volume of point-to-point transmission service has reached a saturation point.

Category 12 - ASSESSMENTS
($7,263,000 Increase; for a 2002 total of $20,989,000)

The 2002 budget reflects a tariff income of $7,500,000, which will not meet 80% of the expenses, therefore resulting in an approximate shortfall for 2002 of $15,291,000.

RTO RELATED EXPENDITURES

The following items represent expenditures SPP could expect to incur should SPP move forward in gaining RTO status. These items are presented for informational purposes only and are not a part of the SPP 2002 Administrative Budget.

New Employees – Staff recommends the addition of two new full time employees in the Information Technology department. Justification for these positions are provided below. ($168,896 in full year salaries, benefits, travel expenses)

Information Technology Specialist II (Two positions) - IT

The Manager of Operations has specifically requested additional staff be added to the Information Technology department and be dedicated to the daily support needs of the Operations department. Two new staff are required to provide this programming support. The dedicated analysts will be responsible for ad-hoc programming, database querying and reporting, and other support activities as may be requested by the Manager, Operations. The President recommends in the first quarter the addition of two full time positions at level 40 compensation with the title “Information Technology Specialist II”. One position will report to the Supervisor, EMS and the other to the Supervisor, Applications and Database Development. These staff would be dedicated to the support of Operations department, providing programming and related support to Coordination Center management and staff.

SPP/NERC Meetings - Staff anticipates additional working group and task force meetings in 2002 to develop and implement congestion management procedures. ($68,400)

Congestions Management - The staff recommends the use of an external software vendor to create the software system to the design approved by the Commercial Practices Committee. The operational cost is not anticipated until 2003. ($5,000,000)

New Employee PCs – Personal computers to support the two additional information technology staff additions. ($18,000)

Legal – Anticipate additional legal expense associated primarily with regulatory filings. ($450,000)

Southwest Power Pool
President's Report & Budget Comparison
Actual vs. Budgeted Expenses (01/01/01-10/31/01)

Expenses		Year to Date			End of Year		
		Actual ($)	Budgeted ($)	Over/ Under ($)	Present Estimate ($)	Budgeted ($)	Over/ Under ($)
(1)	Salaries/Benefits	7,907,676	8,967,757	1,060,081	9,838,735	10,934,800	1,096,065
(2)	Travel Expenses	573,248	440,038	133,210	652,031	514,600	137,431
(3)	Administrative	620,180	413,266	206,914	644,446	436,000	208,446
(4)	NERC Assessment	758,617	966,667	208,050	958,617	1,200,000	241,383
(5)	SPP/NERC Meetings	196,234	194,093	2,141	220,601	222,000	1,399
(6)	Communications	545,521	663,126	117,605	691,221	816,250	125,029
(7)	Capital / Operating	2,263,471	2,200,238	63,233	2,674,911	2,576,000	98,911
(8)	Capital Expenditures	2,639,878	2,699,924	60,046	2,879,078	2,956,600	77,522
(9)	Outside Services	1,331,607	1,721,550	389,943	1,678,080	2,072,000	393,920
(10)	Miscellaneous Income	1,976,563	1,517,645	458,918	2,243,980	1,792,700	451,280
Net Expenses		**14,859,867**	**16,749,014**	**1,889,147**	**17,993,739**	**19,935,550**	**1,941,811**
Income							
(11)	Tariff Income	6,441,869	5,446,087	995,782	7,328,535	6,210,000	1,118,535
(12)	Assessments	8,417,999	11,302,927	2,884,928	10,665,204	13,725,550	3,060,346
Net Income		**14,859,867**	**16,749,014**	**1,889,147**	**17,993,739**	**19,935,550**	**1,941,811**

November 16, 2001

Southwest Power Pool

Board of Directors Summary

Category	2001 Actual vs 2001 Budget: 2001 Present Estimate	2001 Budget	Change	Percent	2002 Budget vs 2001 Actual: 2002 Budget	2001 Present Estimate	Change	Percent	2002 Budget vs 2001 Budget: 2002 Budget	2001 Budget	Change	Percent
1 Salaries / Benefits												
Salaries	7,191,502	7,952,100	760,598	(10%)	10,122,670	7,191,502	2,931,168	41%	10,122,670	7,952,100	2,170,570	27%
Payroll Taxes	508,251	538,182	29,931	(6%)	618,746	508,251	110,495	22%	618,746	538,182	80,564	15%
Benefits	1,789,269	1,984,518	195,249	(10%)	2,900,520	1,789,269	1,111,251	62%	2,900,520	1,984,518	916,002	46%
Relocation/Training	349,713	460,000	110,287	(24%)	378,000	349,713	28,287	8%	378,000	460,000	82,000	(18%)
Subtotal	9,838,735	10,934,800	1,096,065	(10%)	14,019,935	9,838,735	4,181,201	42%	14,019,935	10,934,800	3,085,135	28%
2 Employee Travel Expenses	652,031	514,600	137,431	27%	593,520	652,031	58,511	(9%)	593,520	514,600	78,920	15%
3 Administrative	644,446	436,000	208,446	48%	726,400	644,446	81,954	13%	726,400	436,000	290,400	67%
4 NERC Assessment	958,617	1,200,000	241,383	(20%)	900,000	958,617	58,617	(6%)	900,000	1,200,000	300,000	(25%)
5 SPP/NERC Meetings	220,601	222,000	1,399	(1%)	231,600	220,601	10,999	5%	231,600	222,000	9,600	4%
6 Communications	691,221	816,250	125,029	(15%)	1,396,230	691,221	705,009	102%	1,396,230	816,250	579,980	71%
7 Capital/Operating Leases & Maint.	2,674,911	2,576,000	98,911	4%	4,087,200	2,674,911	1,412,289	53%	4,087,200	2,576,000	1,511,200	59%
8 Capital Expendures	2,879,078	2,956,600	77,522	(3%)	2,022,500	2,879,078	856,578	(30%)	2,022,500	2,956,600	934,100	(32%)
9 Outside Services	1,678,080	2,072,000	393,920	(19%)	6,081,100	1,678,080	4,403,020	262%	6,081,100	2,072,000	4,009,100	193%
10 Misc. Income	2,243,980	1,792,700	451,280	25%	1,569,700	2,243,980	674,280	(30%)	1,569,700	1,792,700	223,000	(12%)
Net Expenses	**17,993,739**	**19,935,550**	**1,941,811**	**(10%)**	**28,488,785**	**17,993,739**	**10,495,046**	**58%**	**28,488,785**	**19,935,550**	**8,553,235**	**43%**
11 Tariff Income	7,328,535	6,210,000	1,118,535	18%	7,500,000	7,328,535	171,465	2%	7,500,000	6,210,000	1,290,000	21%
12 Assessments	10,665,204	13,725,550	3,060,346	(22%)	20,988,785	10,665,204	10,323,581	97%	20,988,785	13,725,550	7,263,235	53%
Net Income	**17,993,739**	**19,935,550**	**1,941,811**	(10%)	**28,488,785**	**17,993,739**	**10,495,046**	**58%**	**28,488,785**	**19,935,550**	**8,553,235**	**43%**

November 16, 2001

2002 Budget Forecast

All Categories

Category	Description of Category	Actuals	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total	RTO Items Only	NEW Budget Totals with RTO Items Included	2001 Actual
		1999	2,177,329	2,245,284	2,105,554	2,311,646	8,839,813			
		2000	2,774,480	3,402,872	2,550,338	2,841,517	11,569,207			
		2001	3,941,436	4,739,872	4,886,314	4,426,117	17,993,739			
(1)	Salaries/Benefits		3,157,155	4,491,213	3,194,387	3,177,179	14,019,935	165,696	14,185,631	9,838,735
(2)	Travel Expenses		150,930	147,330	146,830	148,430	593,520	3,200	596,720	652,031
(3)	Administrative		389,180	235,740	50,740	50,740	726,400	No Change	726,400	644,446
(4)	NERC Assessment		225,000	225,000	225,000	225,000	900,000	No Change	900,000	958,617
(5)	SPP/NERC Meetings		59,130	59,920	54,945	57,605	231,600	68,400	300,000	220,601
(6)	Communications		348,345	349,695	349,095	349,095	1,396,230	No Change	1,396,230	691,221
(7)	Capital/Operating Leases and Maint.		2,629,725	167,325	1,152,825	137,325	4,087,200	No Change	4,087,200	2,674,911
(8)	Capital Expenditures		975,000	381,500	333,000	333,000	2,022,500	5,018,000	7,040,500	2,879,078
(9)	Outside Services		1,616,800	1,511,800	1,468,500	1,484,000	6,081,100	450,000	6,531,100	1,678,080
(10)	Miscellaneous Income		504,225	359,325	352,525	353,625	1,569,700	No Change	1,569,700	2,243,980
Net Expenses			**9,047,040**	**7,210,198**	**6,622,797**	**5,608,749**	**28,488,785**	**5,705,296**	34,194,081	**17,993,739**
(11)	Tariff Income		1,675,000	1,775,000	2,300,000	1,750,000	7,500,000		7,500,000	7,328,535
(12)	Assessments		7,372,040	5,435,198	4,322,797	3,858,749	20,988,785		26,694,081	10,665,204
Net Income			**9,047,040**	**7,210,198**	**6,622,797**	**5,608,749**	**28,488,785**		34,194,081	**17,993,739**

Income Applied to:	**Current**	**Accumulative**
1998 Carryover of	$2,173,508	$2,173,508
1999 Carryover of	$4,244,310	$6,417,818
2000 Carryover of	$3,487,783	$9,905,601
2001 Carryover of	$7,066,456	$16,972,057
2002 Shortfall of	$15,291,028	$32,263,085

Comparison Of Previous 2002 Budget To Current 2002 Budget

Category		Old 2002 Budget Estimates	New 2002 Budget Estimates	% Change	
(1)	**Salaries/Benefits**	**12,383,685**	**14,019,935**	**13.2%**	Old 2002 budget calculated at 2001 budget plus 10% plus $161,600 for two new positions.
	Salaries	8,908,910	10,122,670		
	Payroll Taxes	805,365	618,746		New 2002 budget contains 4.5% merit salary adjustment, three new positions,
	Benefits	2,209,410	2,900,520		one position upgrade, incentive and retention programs approved by the Board.
	Relocation/Training	460,000	378,000		Benefit expenses expected to be 29% of salaries vs. 25% of salaries.
(2)	**Travel Expenses**	**540,365**	**593,520**	**9.8%**	Old 2002 budget calculated at 2001 budget plus 5%.
	Executive	68,640	131,500		New 2002 budget approximates actual 2001 travel expenses.
	Legislative/Regulatory	167,440	180,580		
	Corp. Services	50,710	40,100		
	Coord. Operations	253,575	241,340		
(3)	**Administrative**	**479,600**	**726,400**	**51.5%**	Old 2002 budget calculated at 2001 budget plus 10%. New 2002 budget includes increased D&O and credit insurance coverages.
(4)	**NERC Assessment**	**1,600,000**	**900,000**	**-43.8%**	
	NERC	1,600,000	900,000		
(5)	**SPP/NERC Meetings**	**238,621**	**231,600**	**-2.9%**	Old 2002 budget calculated at 2001 budget plus 7.5%
	Executive	67,095	25,000		New 2002 budget approximates actual 2001 meeting expenses.
	Legislative/Regulatory	98,406	63,200		
	Corp. Services	4,260	14,200		
	Coord. Operations	57,860	119,200		
	Reimb for Nerc Mtgs	11,000	10,000		
(6)	**Communications**	**968,000**	**1,396,230**	**44.2%**	New 2002 budget contains additional $400,000 in expenditures for SPPNET and redundant SPPNET.
	Coord. Operations	968,000	1,396,230		
(7)	**Capital/Operating Leases & Maint.**	**6,524,280**	**4,087,200**	**-37.4%**	Old 2002 budget calculated at 2001 budget plus 3% plus $3,700,000 for payment of principal on the bond issue.
	Corp. Services	505,702	2,390,500		New 2002 budget excludes any repayment of the bond principal, interest totals
	Coord. Operations	6,018,578	1,696,700		$1,875,000.
(8)	**Capital Expenditures**	**$2,031,200**	**$2,022,500**	**-0.4%**	Both budgets based on identified needs.
	Corp. Services	$208,800	$370,000		
	Coord. Operations	$1,572,400	$1,652,500		
	OTS For Training	$250,000	$0		
(9)	**Outside Services**	**$6,150,160**	**$6,081,100**	**-1.1%**	Old 2002 budget calculated at 2001 budget plus 4% plus $4,000,000 for outsource
	Executive	$840,000	$650,000		of market operations via contract with Accenture.
	Corp. Services	$74,160	$75,300		New 2002 budget includes $246,000 for OATI, and $200,000 in COSMOS enhancements
	Coord. Operations	$5,236,000	$5,355,800		
(10)	**Miscellaneous Income**	**$1,828,554**	**$1,569,700**	**-14.2%**	Old 2002 budget calculated at 2001 budget plus 2%.
	Miscellaneous Income	$1,828,554	$1,569,700		New 2002 budget excludes income from AEP (Ohio Project) and includes increased income from SPPNET reimbursements ($526,000).
Net Expenses		**$29,087,357**	**$28,488,785**	**-2.1%**	

Southwest Power Pool
BOARD OF DIRECTORS MEETING
December 12, 2001

Staff Recommendation on Member Termination

Background

As of December 3, 2001, Enron Power Marketing, Inc. (ENRON) has failed to pay SPP its October and November membership assessments of $2,076.57 and $3,104.16 respectively. Given a previous record of timely payments and pursuant to membership agreement requirements (Section 8.10 – Good Faith Efforts), SPP in good faith contacted ENRON representatives on numerous occasions to permit them to fulfill their financial obligations under the membership agreement. SPP Bylaws (Section 7.2 – Assessment) require members to deposit assessments with SPP no later than thirty days after receipt of notification, and if such deposit does not occur within forty days of notification, it shall be considered delinquent and reported to the Board of Directors for appropriate action. On December 2, 2001, ENRON filed for Chapter 11 bankruptcy protection.

Analysis

SPP Bylaws (Section 7.2 – Assessments) provide that the Board of Directors may grant reasonable extensions of time for deposit of delinquent assessments. The Bylaws (Section 2.3 – Removal and Reinstatement) and the Membership Agreement (Section 6.0 – Removal of Members) provide that the Board of Directors may terminate the Membership of any Member for cause including, for example, violation of the SPP Bylaws or nonpayment. A Member terminated by the Board of Directors is obligated to comply with requirements as if it had voluntarily withdrawn from the Membership Agreement, including all financial obligations (see Section 4.2 – Effect of Withdrawal on Contractual Obligations).

ENRON's bankruptcy filing subjected SPP collection of the October and November assessments to the outcome of the related court process. Any future unpaid SPP assessments would not be part of the court docket initiated by ENRON's December 2, 2001 filing. It is highly unlikely that future assessments will be paid and if ENRON wished to terminate its SPP membership, it would have to provide notice by the end of this year for an earliest effective date of October 31, 2002. Until such effective date, financial obligations will continue to be incurred.

Termination of ENRON's membership by the Board of Directors appears to be in the best interest of both ENRON and SPP by ending ENRON's growing debt to SPP as soon as possible. Membership is not a requirement to participate in SPP processes and is not a condition to receive service under the regional transmission tariff. ENRON could apply for reinstatement at a later date provided related conditions are met. If the Board of Directors terminated ENRON's membership, ENRON's financial obligation to SPP, excluding the delinquent assessments, is approximately $185,000. Staff has contacted ENRON representatives to discuss a membership termination approach but has been unsuccessful in receiving a response.

Recommendation

SPP Staff recommends that the Board of Directors terminate the membership of ENRON, Corp. effective immediately.

SPP/MISO Consolidation Legal Update

SPP Board of Directors
December 12, 2001

Purchase & Assumption Agreement

- Excludes assets/liabilities associated with regional reliability council
- Requirements of each company are virtually identical
- Termination provisions are standard and include a December 31, 2002 deadline for closing

Conduct of Business

<u>Sections 7.1(o) and 7.2(o)</u>

SPP and MISO will each be required to receive written consent in order to discuss the sale of assets or another merger/consolidation

Conditions to Closing

- All regulatory and third-party consents obtained
- All revisions to MISO documents adopted
- MISO has initiated tariff administration
- FERC Order expanding MISO-ARTO super-regional rate to SPP footprint
- FERC Order recognizing Resulting Company as an RTO

Conditions to Closing

- SPP Members representing at least 174,000 GWh of Annual Schedule 1 Billing Units have signed Resulting Company Membership Agreement
- MISO Members representing at least 372,000 GWh of Annual Schedule 1 Billing Units shall have signed the Resulting Company Agreement
- SPP Members have executed Conditional Withdrawal Agreement

Exhibits

- Assignment and Assumption Agreement
- Bill of Sale
- Employment Agreement (no longer to be included)
- Amended Certificate of Incorporation

Exhibits Amended Bylaws

MISO Bylaws amended to reflect:

- 11-member Board of Directors
- Super-majority voting required for Board of Directors for initial 6-month term
- Officers and respective duties/authorities
- Advisory Committee will include SPP and MAPP reps for initial terms

Services Agreement

- Agreement between SPP and Resulting Company for services related to reliability council functions
- Services to be provided at cost to SPP
- Effective at Closing Date of consolidation

Membership Transition**

- Ideal is for all current SPP Members to join Resulting Company
- Make transition as smooth as possible for Members
- Avoid violations of current SPP Agreement and Bylaws
- Ensure all current obligations resulting from SPP Agreement are met by SPP/Resulting Company and SPP Members

*** Assumes debt-holder consents to assignment ***

Conditional Withdrawal Agreement

- Allows SPP Members to withdraw without the usual “waiting period”
- Assigns obligations of Member and SPP at effective date to Resulting Company
- Financial obligations to SPP only become due and payable in full if Member does not join Resulting Company

SPP/MISO Membership Comparison

- Penalties for violations
- Removal of a Member
- Limitations on liability to other Owner

SPP/MISO Tariff Comparison

- Load under the Tariff
- Transmission rates
- Adder to recover operating costs
- Losses
- Independent Transmission Companies

Next Steps….

- Finalize Purchase and Assumption Agreement
- Determine terms of a Membership Agreement for the Resulting Company and finalize transition plan
- Develop bylaws and membership agreement for SPP as a regional reliability council only

SPP Southwest Power Pool