**Southwest Power Pool**

**REGIONAL STATE COMMITTEE**

**DoubleTree Hotel at Warren Place – Tulsa, OK**

**October 23, 2006**

**• M I N U T E S •**

**Administrative Items:**

Members in attendance or represented by proxy were:

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

There were 49 in attendance (Attendance & Proxies – Attachment 1). Others in attendance via phone:

Larry Holloway, Kansas Corporation Commission
Tom DeBaun, Kansas Corporation Commission
Walter Wolf, Stone, Pigman, Walther, Wittman, LLC
David Kays, Oklahoma Gas & Electric
Bary Warren, Empire District
Bill Caruso, Global Energy
Jim Soles, Occidential Petroleum Corporation

President Bode called the meeting to order at 1:07 p.m. Cheryl Robertson called roll and a quorum was declared. President Bode asked for adoption of the July 25, 2006 meeting minutes (RSC Minutes 7/25/06 - Attachment 2). Dr. Mike Proctor asked that the records reflect his attendance. President Bode asked for a show of hands to approve the July minutes as corrected. She then asked for adoption of the August 16, 2006 teleconference minutes (Minutes 8/16/06 – Attachment 3). Hearing no addition or corrections, the August minutes were approved by a show of hands.

**Election of officers**

President Bode stated that this was the RSC Annual Meeting which requires the election of officers. Mr. Steve Gaw moved to nominate Commissioner Julie Parsley for President; Commissioner Brian Moline for Vice President, and Commissioner Sandra Hochstetter for Secretary/Treasurer. Commissioner Moline seconded the motion, which passed unanimously. President Bode was thanked for her great leadership and development of this organization. President Bode stated that the RSC was leading the nation as a model for this type of organization and had great opportunities to break ground.

President Bode then asked for a round of introductions including those joining via phone.

**Updates:**

RSC Financial Report

Les Dillahunty (SPP) presented the RSC Financial Report (RSC Financial Report – Attachment 4). Mr. Dillahunty reported that the RSC remained well under budget in large part due to the fact that no Cost Benefit Study was conducted. The bulk of expenses incurred to date are meeting expenses.

RSC Officer Reports

President Bode shared that she had had the opportunity to witness a deployment test at Oklahoma Gas & Electric (OG&E). She said that SPP had a good process and felt good about SPP's response to market issues. She called attention to the National Edison Electric Institute Report and stressed that RSC needed to work to achieve the building of new transmission to meet native loads.

FERC Update

Tony Ingram provided an update on FERC activities:

FERC recently voted orders addressing:

- Loss compensation methodology requiring that all generators providing this service should be compensated
- Market participant agreement and reserve cost allocation
- An order on rehearing of its March, 2006 order regarding SPP's energy imbalance market

Pending Commission action items are:

- Balancing Authority settlement agreement
- SPP's filing of a meter agent agreement and market readiness metrics including a statutory action item

Other recent Commission actions include:

- Approval of NERC's proposed ERO budget and 83 ERO reliability standards
- Approval of the funding of NERC ERO statutory activities, under EPAct 2005 and funding of Regional Entitiy statutory activities through the ERO
- Issuance of a final rule addressing PURPA requirements

SPP Update

Nick Brown provided an update on SPP activities (SPP Report - Attachment 5). Mr. Brown addressed three topics:

- RSC's success in issues such as: cost allocation for Reliability Upgrades; the approval of 40 projects for Base Plan funding in the amount of $69 million; and Unintended Consequences, allocation of transmission costs and waivers.
- A request for RSC's continued support: focus on cost allocation for economic upgrades; an efficiency initiative utilizing EPRI building blocks; and continued support at FERC.
- The point that 10% of the electrical infrastructure; i.e. transmission was limiting the other 90% of the infrastructure (generation, markets).

**Business Meeting:**

2007 Budget Approval

Les Dillahunty provided a review of the 2007 RSC Budget (Budget – Attachment 6). Mr. Dillahunty explained the budget process using history to produce the figures for 2007 and a 3% increase for 2008. In discussion, it was decided to break for a short budget discussion to possibly allow for more flexibility. Action will be taken later in the meeting.

The annual audit is underway and a full report will be given at the January meeting.

<u>December 11, 2006 Technical Conference Agenda</u>
Joyce Davidson provided a review of the draft agenda for the SPP Technical Conference on Regional Resource Planning (SPP Technical Conference – Attachment 7). She stated that the date had been moved to January 19, 2007 in San Antonio. Following discussion, it was decided to hold the conference either prior to the RSC meeting on January 29 or following the SPP Board of Directors meeting January 30. The selected date will be announced. Ms. Davidson and Les Dillahunty will continue to work on conference details.

<u>CAWG Report</u>
Dr. Mike Proctor provided a review of the CAWG White Paper and proposed revisions to Attachment Z (CAWG Report - Attachment 8). He stated that action would not be required at this time but that the final white paper would be ready for approval at the January RSC meeting. Mike also provided a brief overview of the CAWG's efforts to address options for economic upgrades.

<u>EIS Market Update</u>
Les Dillahunty provided a status report on the EIS Market Implementation (EIS Market Status – Attachment 9). Mr. Dillahunty reviewed deployment tests conducted since August 1. He also addressed the status of critical readiness issues including: LIP volatility, market metrics and the reserve sharing arrangements that impact EIS Market readiness.

<u>Base Plan Projects Approval</u>
Dennis Reed (Westar) provided information regarding Unintended Consequences and changes to Schedule 2 of the Tariff (Base Plan Projects & Reactive Compensation – Attachment 10). The Regional Tariff Working Group (RTWG) formed the Interzonal Cost Allocation Task Force (IZATF) to review Unintended Consequences options. This group is to report back to the RTWG in order for RTWG to present a final recommendation to the MOPC, RSC and BOD in January.

Mr. Reed commented that the necessary changes to Schedule 2 are almost complete with the exception of the impact analysis.

<u>OG&E and Golden Spread Base Plan Projects Waiver Requests</u>
Les Dillahunty reviewed waiver requests as allowed in Attachment J of the SPP Tariff from Oklahoma Gas and Electric (OG&E) and Golden Spread Electric Cooperative (GSEC) (Waiver Requests – Attachment 11). The MOPC took the following action with regard to these waiver requests:

- Rejected SPP Staff's recommendation on OG&E waiver request.

- Directed SPP Staff to present and discuss its recommendation in addition to the criteria used to evaluate a waiver to the CAWG for their direction and recommendation prior to the next MOPC meeting.

- Recommendation to the BOD that unusual circumstances exist with the OG&E waiver and the 120 day deadline should be extended to the end of January, 2007.

- Westar waiver not considered at MOPC as request not received until October 13, 2006.

2007 Budget Approval - continued
President Bode presented the results of the RSC Budget discussion. The RSC Budget is planned for a two year cycle. RSC staff recommended an additional $53,000 be added to the draft 2007 and the 2008 budget years. This increase is due mostly to travel and the expectation of additional meetings. **Vice President Parsley moved to approve the 2007 & 2008 Budget as amended. Commissioner Gaw seconded the motion, which passed unanimously.**

**Scheduling of Next Regular Meeting, Special Meetings or Events:**
President Bode noted that the next regularly scheduled RSC meeting is in San Antonio, Texas on January 29, 2007. If needed, a teleconference will be scheduled to discuss the January Technical Conference agenda.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty

# AGENDA

## ANNUAL MEETING *
## Monday, October 23, 2006
## 1:00 pm- 5:00 pm
## DoubleTree Hotel at Warren Place
### Tulsa, Oklahoma

1. **CALL TO ORDER**
2. **PRELIMINARY MATTERS**
   a. **Declaration of a quorum**
   b. **Adoption of July 24 and August 16, 2006 Minutes**
3. **ELECTION OF OFFICERS**
4. **UPDATES**
   a. **RSC Financial Report**
   b. **Other RSC officer reports**
   c. **FERC**
   d. **SPP**
5. **BUSINESS MEETING (ALL ITEMS SUBJECT TO DISCUSSION AND ACTION)**
   a. **2007 Budget Approval (ACTION REQUESTED) ........................................................ Les Dillahunty**
   b. **December 11, 2006 Technical Conference Agenda (Discussion & Approval)...... Joyce Davidson**
   c. **CAWG Report**
      1. **Attachment J & Z White Paper (ACTION REQUESTED) .................................. Dr. Mike Proctor**
      2. **Status of Development of an Alternative Approach to the Funding of Economic Upgrades**
      3. **Other Items**
   d. **EIS Market Update .......................................................................................... Lanny Nickel**
   e. **Base Plan Projects Approval**
      1. **Report of Further Unintended Consequences Analysis and Recommendation . Dennis Reed**
      2. **Report of the Reactive Compensation Task Force Proceedings**
   f. **OG&E and Golden Spread Base Plan Projects Waiver Requests**
      1. **SPP Recommendation .................................................................................. Les Dillahunty**
      2. **MOPC Action................................................................................................... Robin Kittel**
      3. **OG&E Analysis & Recommendation ........................................................ Mike Sherriff**
      4. **Golden Spread Analysis & Recommendation ............................................. Mike Wise**
      5. **Discussion**
6. **SCHEDULING OF NEXT REGULAR MEETING, SPECIAL MEETINGS OR EVENTS**
7. **ADJOURNMENT**

* Background materials will continue to be posted in advance of the scheduled meeting as they become available.

Southwest Power Pool

**Southwest Power Pool**
**REGIONAL STATE COMMITTEE**
**Doubletree Hotel at Warren Place – Tulsa, Oklahoma**
**October 23, 2006**

## ATTENDANCE LIST

| Name | System |
| --- | --- |
| Michael Desselle | SPP |
| Mel Perkins | OGE |
| Richard Spring | KCPL |
| Gary Roulet | WFEC |
| Walt Shumate | Shumate Assoc. - On Behalf of ESI |
| Bill Wylie | OG&E |
| Terri Eaton | Xcel |
| Ricky Bittle | |
| Lanny Nickell | SPP |
| Les Dillahunty | SPP |
| Harry Skilton | SPP Director |
| Quentin Jackson | SPP Director |
| Jim Eckelberger | SPP Director |
| Nick Brown | SPP President |
| Richard House | Ark PSC |
| Adrianne Brandt | PUCT |
| Joyce Davidson | OCC |
| Ted Thomas | Ark P.S.C. |
| Steve Gaw | Mo P.S.C. |
| Denise Bode | OK Corp Comm. |

SPP Southwest Power Pool

**Southwest Power Pool**
**REGIONAL STATE COMMITTEE**
**Doubletree Hotel at Warren Place – Tulsa, Oklahoma**
**October 23, 2006**

## ATTENDANCE LIST

| Name | System |
|---|---|
| Julie Parsley | Texas PUC |
| BRIAN MOLINE | Kans Corp Comm |
| Mike Proctor | Missouri PSC |
| Rob Janssen | Redbud Energy |
| Matt Towne | KCC Staff |
| Tim Woolley | Xcel Energy |
| Venita McCellon-Allen | AEP SWEPCO |
| Richard Ross | AEP |
| Stuart Solomon | PSO |
| Larry Altenbaumer | Director |
| Mike Wise | GSEC |
| Tony Ingram | FERC |
| JOHN ROGERS | FERC |
| Steve Owens | ENTERGY Services, Inc. |
| RON MUCCI | WILLIAMS POWER Co. |
| Carl Huslig | ITC Great Plains |
| David Douglass | Aquila, Inc. |
| BOB KOENIG | OG&E |
| JOHN COOPER | WILLIAMS POWER CO. |
| RICK WALKER | THE WIND COALITION |

Southwest Power Pool

# Southwest Power Pool
## REGIONAL STATE COMMITTEE
## Doubletree Hotel at Warren Place – Tulsa, Oklahoma
## October 23, 2006

## ATTENDANCE LIST

| Name | System |
|---|---|
| Bobby Wegener | State of Oklahoma |
| Ron Gary | LUS |
| Tom Stuchlik | Westar |
| Lamona Lawrence | SPP |
| Cheryl Robertson | SPP |
| Shah Hossain | Westar |
| David Brian | |
| Jeff Knotter | CUS |
| Dennis Reed | Westar |

Sandra L. Hochstetter
Chairman
(501) 682-1455

Daryl E. Bassett
Commissioner
(501) 682-1453

Randy Bynum
Commissioner
(501) 682-1451

**ARKANSAS**
**PUBLIC SERVICE COMMISSION**
**1000 Center**
**P.O. Box 400**
**Little Rock, Arkansas 72203-0400**
**http://www.Arkansas.gov/psc**

October 18, 2006

Mr. Les Dillahunty
Secretary
SPP Regional State Committee
415 N. McKinley
#140 Plaza West
Little Rock, AR 72205-3020

Dear Les:

I will not be able to attend the October 23, 2006 RSC meeting. By this letter, I hereby give my proxy to Ted Thomas.

Sincerely,

Sandra L. Hochstetter
Sandra L. Hochstetter

cc: The Honorable Julie Parsley

**Notice of Meeting of the Southwest Power Pool Regional State Committee**

The Southwest Power Pool (SPP) Regional State Committee (RSC) will hold a public meeting at 1:00 pm CDT on October 23, 2006. The business meeting will involve discussion and possible action as set forth in the attached Agenda. Members who are not able to attend in person should submit a proxy in accordance with the Bylaws.

Persons planning to attend the meeting by teleconference should register online at least one day prior to the meeting at http://www.spp.org in order to obtain the telephone number for conference bridge access. The telephone number will be provided at close of business the day before the meeting.

RSC Regional State Committee
FOR THE SOUTHWEST POWER POOL

1000 Center St. Little Rock, AR 72201

**Southwest Power Pool**

**REGIONAL STATE COMMITTEE**

**Embassy Suites Hotel/Kansas City Plaza – Kansas City, MO**

**July 24, 2006**

**• M I N U T E S •**

**Administrative Items:**

Members in attendance or represented by proxy were:

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

There were 41 in attendance (Attendance & Proxies – Attachment 1). Others in attendance via phone:

Sandra Hochstetter, Arkansas Public Service Commission
Richard House, Arkansas Public Service Commission
Adrainne Brandt, Public Utility Commission of Texas
Bridget Headrick, Public Utility Commission of Texas
Larry Holloway, Kansas Corporation Commission
Karen Forbes, Oklahoma Corporation Commission
Ed Farrar, Oklahoma Corporation Commission
Ryan Kind, Missouri Office of the Public Counsel
Walter Wolf, Stone, Pigman, Walther, Wittman, LLC
Gary Roulet, Western Farmers
Robert Shields, Arkansas Electric Cooperative Corporation
Jay Caspary, Southwest Power Pool, Inc.
David Kays, Oklahoma Gas & Electric
David Brian, East Texas Cooperatives
Raksha Krishna, EEI

Vice President Parsley called the meeting to order at 2:05 p.m. Cheryl Robertson called roll and a quorum was declared. Vice President Parsley asked for adoption of the April 24, 2006 meeting minutes (RSC Minutes 4/24/06 – Attachment 2). **Commissioner Steve Gaw moved to adopt the April 24, 2006 minutes. Chair Brian Moline seconded the motion. Hearing no objection, the minutes were approved by acclamation.**

**Updates:**

RSC Financial Report

Les Dillahunty (SPP) presented the RSC Financial Report (RSC Financial Report – Attachment 3). Mr. Dillahunty reported that the RSC remained well under budget including expenses for the Cost

Allocation Working Group. He stated that there is preparation underway for the 2007 Budget which will be ready for RSC approval at its October meeting. A copy of the 2007 Budget will be distributed in advance of the October meeting for review.

RSC Officer Reports
Vice President Parsley asked for updates from the RSC officers. Hearing none she continued with reports.

FERC Update
John Rogers provided an update on FERC activities:

- U.S. Senate confirmed three new FERC commissioners, which makes a full complement of five commissioners.
- FERC certified the North American Electric Reliability Council (NERC) as the Electric Reliability Organization (ERO) and plans to issue a rulemaking later this year on the reliability standards submitted by NERC.
- The Commission issued a final rule Promoting Transmission Investment to increase investment in the grid and improve reliability. The Commission adopted most of the proposals contained in the Notice of Proposed Rulemaking (NOPR) including:
  - Incentive ROEs;
  - Full recovery of construction work in progress;
  - Accelerated depreciation, and;
  - Higher rates of return for utilities that join and/or continue to be members of RTOs.

  Any rates or incentives proposed by utilities would have to be filed with and approved by the Commission. In addition, in separate orders, the Commission had approved certain incentive rates for AEP and Allegheny Energy transmission projects consistent with the final rule incentives.
- The Commission issued a final rule on Long-Term Transmission Rights for Electricity Markets as a result of a mandate of EPAct 2005. The final rule adopted seven guidelines for transmission organizations to follow in developing proposals for long-term firm transmission rights.
- In May, the Commission issued a NOPR on changes to the Open Access Transmission Tariff. Comments are due to the Commission by August 7.
- In June, the Commission issued proposed rules to implement the backstop transmission citing provisions of EPAct 2005. EPAct 2005 granted the Commission limited transmission citing authority for transmission facilities located in national interest electric transmission corridors.

SPP Update
Nick Brown provided an update on SPP activities:

- With NERC receiving certification as an ERO, SPP will now seek authority as a Regional Entity (RE) under the new structure. SPP met on July 18 with Rick Sergel and Dave Cook (NERC) to discuss SPP's plan to seek RE status as well as remain a Regional Transmission Organization (RTO). Filings will be required. SPP plans to stay in close touch with the RSC throughout the process.
- SPP's first priority is the EIS Market Implementation. For the future, the 2005 Strategic Plan has been reviewed and a draft 2006 Strategic Plan developed for longer term.
- The addition of transmission in the SPP footprint has been significant, adding $250,000,000 through the end of 2007. SPP experienced peak days on July 17, 18 and 19 without impact

to reliability.

- SPP is revamping and expanding the Emergency Response Plan and intends to have a new plan to present at the December Board of Directors meeting.
- There are concerns regarding the FERC Order 888 NOPR. A planned response is needed.
- Dockets are close to completion in Missouri, Arkansas, and Kansas for RTO recognition. SPP is looking forward to the final orders. There are still state filing obligations in New Mexico and Louisiana for SPS and SWEPCO respectively.

Vice President Parsley then asked for a round of introductions including those joining via phone.

**Business Meeting:**

Draft SPP Strategic Plan Review

Richard Spring (KCPL) provided a review of the SPP Strategic Plan (2005 & 2006 Strategic Plans – Attachment 4). The Strategic Planning Committee (SPC) held a retreat in June to review the 2005 Strategic Plan, which was short term (12 – 18 months) and draft the 2006 Strategic Plan, designed for long term (5 years). Mark Rossi (Gestalt) facilitated the retreat and Rick Able (Prudential) acted as a financial resource. Input will be solicited from the Membership as to what SPP needs to accomplish and how to accomplish it. Comments were provided by the RSC on the draft Strategic Plan

SPP will begin the annual self-assessment/survey on August 1, results will be complied by mid September, discussion held with the organizational groups in late September, and information provided to the Markets and Operations Policy Committee in October. The Board of Directors/Members Committee, and RSC will review the results at their December meeting.

EIS Market Implementation

Carl Monroe (SPP) provided an update on the EIS Market implementation (EIS Market Presentation – Attachment 5). Factory acceptance and testing are complete and the system is in place with deployment tests being conducted in August on a weekly basis. Some participants are concerned with readiness, especially for mid August tests. The MOPC followed by the SPC have recommended to the SPP Board of Directors that the EIS Market start parallel operations on October 1 with binding settlement starting on November 1. If the SPP Board approves a November 1 implementation date, the MWG recommends that the Market Implementation Task Force and SPP Staff evaluate/determine the best use of time during the month of October.

NERC's Registered Ballot Body is conducting a re-ballot which is due on July 26 in conjunction with SPP's requested variances in support of the EIS market.

SPP/IRC Approach to FERC Order 888 Reform

Les Dillahunty reviewed the FERC Order 888 NOPR (FERC Order 888 –Attachment 6). Comments on this order are due August 7 and FERC filings are to be made within 90 days of the final rule. There are 8 requirements in the draft NOPR for Tariff planning processes. It is SPP's position that it is unnecessary and costly to require RTOs/ISOs to re-justify their entire tariffs. It is suggested that the RTOs/ISOs conform their tariffs to the final rule but any further burden to justify existing tariff provisions would be dependent upon a complaint being filed on a case by case basis or to accommodate into the Tariff new provisions of an OATT arising from this process.

Base Plan Projects & Unintended Consequences Review

Dennis Reed reviewed Base Plan Upgrades highlighting major projects (Base Plan Projects and

Unintended Consequences Report – Attachment 7). Mr. Reed reviewed unintended consequences related to the allocation of cost from the Base Plan Upgrades. The Regional Transmission Working Group (RTWG) reviewed results from the SPP Transmission Plan and found the allocation of costs between Zones to be inconsistent. It is recommended that the RTWG be directed to change the current Attachment S to use the Sum of Positive MW-Mile impacts for the Base Plan Zonal Allocations due to the fact that current methodology of using the Net Change MW-Mile impact is flawed. The RTWG wants to study this issue in more detail to see if additional changes are required in the future. Following discussion, **Vice President Parsley moved to: Delay a decision on whether to change the current MW Mile allocation to a different and more appropriate the methodology to the October 23, 2006 RSC meeting after the RTWG evaluation of the most appropriate methodology utilizing completed projects. Commissioner Gaw seconded the motion, which passed unanimously.**

Les Dillahunty inquired about the upcoming Fall Technical Conference and a potential date (Fall Technical Conference – Attachment 8). It is imperative to schedule soon so as to secure meeting space. Following discussion, it was decided that the RSC would meet in two weeks via teleconference to decide if and when to hold a Fall Technical Conference.

<u>SPP Transmission Expansion Projects Status Report</u>
Dr. Mike Proctor stated that there was no presentation from the CAWG for today regarding transmission expansion projects (Base Plan Projects – Attachment 9). Transmission Summits were held in May and June and most questions and issues have been addressed. Dr. Proctor commended Bary Warren (Empire) for being very active in raising good questions regarding these projects. Dr. Proctor's comments were offered in connection with the SPP presentation of Base Plan Projects.

<u>Cost Allocation Working Group</u>
Dr. Mike Proctor (MOPSC) provided an update on the Cost Allocation Working Group (CAWG). The CAWG and stakeholders have developed an issues list for changes needed to be made in Attachment Z. These modifications will be reviewed in August and then presented to the RTWG.

**<u>Scheduling of Next Regular Meeting, Special Meetings or Events</u>:**
Vice President Parsley noted that the next regularly scheduled RSC meeting is in Tulsa, Oklahoma on October 23, 2006. The group was reminded that a conference call will be scheduled in two weeks to discuss a Fall Technical Conference.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty

**Southwest Power Pool**

**REGIONAL STATE COMMITTEE**

**Teleconference**

**August 16, 2006**

**• M I N U T E S •**

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

Others in attendance:
- Adrianne Brandt, Public Utility Commission of Texas
- Bridget Headrick, Public Utility Commission of Texas
- Mike Proctor, Missouri Public Service Commission
- Tom DeBaun, Kansas Corporation Commission
- Matt Tomc, Kansas Corporation Commission
- Tony Ingram, Federal Energy Regulatory Commission
- Harry Skilton, SPP Director
- Nick Brown, Southwest Power Pool, Inc.
- Cheryl Robertson, Southwest Power Pool, Inc.
- Lamona Lawrence, Southwest Power Pool, Inc.
- Gerrud Wallaert, Southwest Power Pool, Inc.
- Kelly Harrison, Westar
- Tom Stuchlik, Westar
- Steve Owens, Entergy
- Rob Gramlich, American Wind Energy Association
- Bill Wylie, OG+E
- Tim Woolley, Xcel Energy

Vice President Parsley called the teleconference to order at 10:10 a.m. Participants identified themselves and a quorum was declared. Vice President Parsley stated that the purpose of this meeting was to discuss the SPP Fall Technical Conference, including setting a date and the agenda.

**Business Meeting:**
Commissioner Sandra Hochstetter provided background for the proposed SPP Fall Technical Conference. She stated that at a planning retreat held in Hot Springs, Arkansas in May 2005, a need was recognized to conduct a workshop facilitated by SPP regarding a regional integrated resource plan (IRP). This regional resource planning process would encompass the transmission

needs and generation requirements over the SPP footprint to determine energy needs. A regional plan would be more effective than plans on an individual state basis and optimize investment costs as well as be a great source of knowledge. Commissioner Hochstetter asked that Nick Brown provide thoughts from SPP and inquired about SPP's modeling tools. Mr. Brown stated that SPP has the modeling capabilities, with some protected by the Tariff for confidentiality while some are not. Modeling tools not available from SPP can be obtained with rather inexpensive software. He also stated that it might be beneficial to compare with other regions' resource plans, noting benefits and impediments. Mr. Brown offered that the Electric Power Research Institute (EPRI) recently held a technical conference, which was executed extremely well and highlighted four areas: 1) Communications Infrastructure, 2) Smart End-Use Devices, 3) Innovative Markets and 4) Innovative regulation and rates. Mr. Brown suggested that it might be beneficial to couple with EPRI in planning and have them present the demand side management and SPP could address the generation/transmission alternatives. Mr. Brown also suggested moving the date from the suggested October 30 or November 3 to later in the year. With the SPP Market Implementation on November 1, it would be difficult to have enough staff available to plan a technical conference and do it justice. It was the consensus of the group to move the date to December 11, the day prior to the SPP Board of Directors meeting on December 12, in Dallas, Texas. Joyce Davidson (OCC) and Sam Loudenslager (APSC) were asked to revise the draft agenda concentrating on items three through six (Attachment). The agenda will be distributed to the committee for review prior to its October 23 meeting.

Dr. Mike Proctor asked the committee for direction as to the Cost Allocation Working Group's (CAWG) next step for economic upgrades. It was agreed that CAWG would develop options to present to the committee by the December SPP Technical Conference.

**Scheduling of Next Regular Meeting, Special Meetings or Events:**
Vice President Parsley noted that the next regularly scheduled RSC meeting is in Tulsa, Oklahoma on October 23, 2006.

With no further business, the meeting was adjourned.

Respectfully Submitted,

Les Dillahunty

**Regional State Committee**
**For the Nine Months Ending September 30, 2006**
**Budget vs. Actual**
**DRAFT**

| | Sept Actuals | Sept Budget | Variance | YTD Actuals | YTD Budget | Variance | | Annual Budget |
|---|---|---|---|---|---|---|---|---|
| **Income** | | | | | | | | |
| Other Income | $ 9,094 | $ 120,710 | $ (111,616) | $ 54,671 | $ 386,397 | $ (331,726) | **(A)** | $ 448,530 |
| **Total Income** | 9,094 | 120,710 | (111,616) | 54,671 | 386,397 | (331,726) | | 448,530 |
| **Expense** | | | | | | | | |
| Meetings | 9,094 | 20,710 | (11,616) | 54,671 | 186,397 | (131,726) | **(B)** | 248,530 |
| Cost Benefit Studies | | 100,000 | (100,000) | | 200,000 | (200,000) | **(C)** | 200,000 |
| **Total Expense** | 9,094 | 120,710 | (111,616) | 54,671 | 386,397 | (331,726) | | 448,530 |
| **Net Income (Loss)** | - | - | - | - | - | - | | - |

**(A) YTD revenue is less than budget given that ytd expenses are less than budget.**

**(B) YTD meeting costs are less than budget due to less than anticipated costs associated with meetings held ytd**

**(C) YTD study costs are less than budget as no studies have been conducted in 2006.**

Southwest Power Pool

**Helping our members work together to keep the lights on...**

***today & in the future***

Southwest Power Pool

Regional State Committee Annual Meeting

**Nick Brown, President and CEO**

October 23, 2006

Southwest Power Pool

## RSC Successes – THANK YOU!

Cost allocation for Reliability Upgrades

April – MOPC & BOD approve 40 projects for base plan funding $69 million

January – Next iteration

Unintended Consequences – allocation & waivers

WWW.SPP.ORG

Southwest Power Pool

## What SPP Needs from its RSC!

**Emphasis on cost allocation for economic upgrades - 10% constraining 90%**

**Efficiency Initiative - EPRI Building Blocks**
- **Innovative Rates and Regulation**
- **Telecommunications**
- **End-Use Devices**
- **Market Innovation**

**Continued support at FERC**

WWW.SPP.ORG

SPP Southwest Power Pool

Nick Brown
President and CEO
501.614.3200
nbrown@spp.org

# SPP REGIONAL STATE COMMITTEE
# 2007 & 2008 ESTIMATED BUDGET

| | ***ESTIMATED FY BUDGET 2007*** | ***ESTIMATED FY BUDGET 2008*** | |
|---|---|---|---|
| **Expense Category** | | | |
| **Travel** | | | |
| RSC Board Meetings | 27,000 | 27,810 | |
| RSC Working Groups | 18,000 | 18,540 | |
| **Total Travel** | **45,000** | **46,350** | 3% Increase |
| **Meetings** | | | |
| RSC Board Meetings | 21,000 | 21,630 | |
| RSC Working Groups | 42,000 | 43,260 | |
| RSC Teleconference | 7,000 | 7,210 | |
| **Total Meetings** | **70,000** | **72,100** | 3% Increase |
| **Administrative** | | | |
| Annual Audit | 3,500 | 3,605 | |
| IRS-RSC Filing | 400 | 412 | |
| NARUC Phone Lines | 300 | 309 | |
| MARC Rental Equip | 200 | 206 | |
| Miscellaneous | 100 | 103 | |
| **Total Administrative** | **4,500** | **4,635** | 3% Increase |
| **Cost Benefit Study** | **700,000** | **-** | |
| **Total Expenses** | **819,500** | **123,085** | |

# SPP REGIONAL STATE COMMITTEE
## HISTORICAL EXPENSE DETAIL
## TRAVEL AND ADMINISTRATIVE EXPENSE

| | Jan-05 | Feb-05 | Mar-05 | Apr-05 | May-05 | Jun-05 | Jul-05 | Aug-05 | Sep-05 | Oct-05 | Nov-05 | Dec-05 | Jan-06 | Feb-06 | Mar-06 | Apr-06 | May-06 | 17 Month Total | Avg | Annual |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Expense** | | | | | | | | | | | | | | | | | | | | |
| 6000 - Operating Expenses | | | | | | | | | | | | | | | | | | | | |
| 6200 Meeting Related Travel | 7,893 | 7,082 | 1,324 | 1,705 | 7,399 | 459 | 3,783 | 3,340 | 1,579 | 3,721 | 4,266 | 3,539 | 917 | 1,383 | 11,221 | 1,452 | 1,393 | 62,456 | 3,674 | 44,087 |
| 6300 Administrative | | | | | | | | | | | | | | | | | | | | |
| IRS-RSC Filing | | 500 | | | | | | | | | | | | | | | | 500 | 29 | 353 |
| Transcripts | | 1,362 | | | | | | | | | | 2,032 | | | | | | 3,394 | 200 | 2,396 |
| NARUC Phone Lines | | | | 419 | | | | | | | | | | | | | | 419 | 25 | 296 |
| MARC Rental Equip | | | | | | | | 265 | | | | | | | | | | 265 | 16 | 187 |
| CPA | | | | | | | | 1,000 | | | | | | | | | | 1,000 | 59 | 706 |
| Total Administrative | - | 1,862 | - | 419 | - | - | - | 1,265 | - | - | - | 2,032 | - | - | - | - | - | 5,578 | 328 | 3,937 |
| TOTAL OPERATING EXPENSE | 7,893 | 8,944 | 1,324 | 2,124 | 7,399 | 459 | 3,783 | 4,605 | 1,579 | 3,721 | 4,266 | 5,571 | 917 | 1,383 | 11,221 | 1,452 | 1,393 | 68,034 | 4,002 | 48,024 |

**Proposed SPP Technical Conference On**
**Regional Resource Planning**

1. Introductory Overview

   - What could and should be required in considering Integrated Regional Planning (regional planning for transmission, generation and demand response)?

2. Generation Planning

   - How do SPP members currently approach generation planning?
   - Given state and federal affiliate requirements, how can generation and transmission be simultaneously evaluated?
   - How do other regions of the country incorporate generation into evaluating long term capacity needs? (ISO-NE, CAPX 2020, WECC)

3. Transmission Planning

   - Compare SPP with other regional organizations in terms of approach; breadth/scope of regions; seams management; types of investments (i.e., reliability vs. economic investments).
   - Are other RTOs or regional planning councils (i.e., WECC) having greater success than SPP in actually getting transmission built? If so, to what can that success be attributed?

4. Demand Response

   - What is the potential market size for demand response in SPP, particularly what amount of industrial/commercial load could readily participate?
   - How can rate design help conserve energy, shave peak load, provide for demand response?
   - What does FERC require in demand response markets?

5. Regional Resource Planning and Use of Demand Response in Other Regions

   - How does this occur (PJM, WECC, New England ISO) and what level of success has been realized?

- What time horizons are used for planning generation, transmission and demand response (i.e., 1 year, 3 years, etc.) in other regions?
- What could and should be required in considering Integrated Regional Planning (regional planning for transmission, generation and demand response)?

6. What Can SPP do to improve or do differently to achieve objectives of "regional IRP"? (i.e., cost savings and synergies associated with the regional evaluation of generation, transmission, and demand response investment)
   - Does SPP incorporate utility generation plans in their plans for assessing transmission needs? If so, how is this question approached? Do other regions? If so, how?
   - What are the prerequisite elements that would need to be in place in order for the RTO to facilitate integrated regional planning (i.e., provide a consultative role to state regulators)?

7. How can state IRP results be utilized or incorporated into the regional planning process for the SPP region?

# CAWG White Paper Proposed Revisions to Attachment Z

Presentation to SPP RSC

October 23, 2006

## Need for Revision

- NEW ENTITY: PROJECT SPONSOR
  - Current Attachment Z envisions the Assignees of Assigned Costs for upgrades to come from transmission service requests.
  - Revised Attachment Z proposes revenue sharing for Assignees of Assigned Costs for upgrades that did not submit a transmission service request.
- NEW TARIFF: ATTACHMENT J
  - Current Attachment Z originally focused on PTP transmission service taken subsequent to the upgrade.
  - Revised Attachment Z also includes specific recommendations for Designated Resource requests subsequent to the upgrade, as well as reliability use from load growth.

2

## Structure of White Paper

I. Background

II. Recommended Changes

  A. Project Sponsors

  B. Designated Resources

  C. Load Growth

  D. PTP Transmission Use

  E. Revenue Credits vs. Lump Sum

III. Alternatives for Unresolved Issues

3

## Background

- Assigned Upgrades where the revenue requirements of the cost of the upgrade are collected from an Assignee.
  - Economic Upgrades
  - New or Changed Designated Resources (DRs)
  - Long-Term PTP transmission service
- Addition of Attachment J and Economic Upgrades results in a broader application of Attachment Z than was originally envisioned even with FERC adding subsequent Network Service Use to the original SPP filing.

4

## A. Project Sponsors

- Adding them requires a division of Attachment Z between aggregate study process for TCs and revenue credits that include Project Sponsors.
- Lump-Sum Payments from Project Sponsors should be allowed.
- Continue to set limits on revenue credits received by Project Sponsors.

5

## B. Designated Resources

- Set out as a distinct category in Attachment Z - requires an allocation of the cost of a previously Assigned Upgrade being used by the new or changed DR.
- Cost from Assigned Upgrades included in Attachment J calculations; e.g., $/MW related to safe harbor provision.
- Included in “higher of” pricing when DR is requested via PTP service, as well as in “and” pricing when DNR is requested via NITS.
- Revenue credits no longer paid because of direction; instead based on the need of the Assigned Upgrade to provide the additional transmission service.
- Appendices showing examples of the calculations are included in white paper.

6

## C. Load Growth

- Set out as a distinct category in Attachment Z - requires an allocation of the cost of a previously Assigned Upgrade being used by the load growth via the SPP transmission plan.
- Remove costs of reliability upgrades displaced by Assigned Upgrades from the costs allocated to the Assignee – include these costs in Base Plan Funding.
- Pay Assignee revenue credits from future displacement of reliability projects – payments come from revenues generated by including displaced costs in Base Plan Funding.

7

## D. PTP Use

Same as current tariff except in two key areas:

1. Revenue credits do not depend on the direction of the subsequent transmission service take, instead SPP will determine that the transmission service could not have been taken without the Assigned Upgrade.
2. Allocations to Project Sponsors based on incremental capacity of the Assigned Upgrade.

Note: These are the areas that the CAWG will need to finalize in its November 1 meeting.

8

## E. Revenue Credits vs. Lump Sum

- Revenue credits when Assignee is paying on a revenue requirements basis
  – no lump sum payments.
- Allow lump sum payment when Assignee has made or completed payments up front.

9

## Alternative Proposals

- Proposals for evaluation of speculative or competing alternative transmission upgrade projects.
- Proposals for allowing Project Sponsors to benefit from the Aggregate Study process.
- Proposals for completion of the Aggregate Study process in a timely manner.
- Alternatives involving technical/calculation details in Attachment Z.; e.g., depreciation, period for receiving revenue credits.
- Alternatives involving
  – Attachment J: 125% reserve limit
  – SPP Plan: Applying “but for” to assigned upgrades
  – Including Assigned Upgrades in of “higher of” pricing.

10

## Next Steps

- Finalize White Paper at November 1 CAWG meeting.
- Presentation of White Paper to the RTWG at November 2 meeting.
  – Schedule to discuss alternatives in Section III.
  – Schedule to redraft tariff language for Attachment Z.

11

# CAWG WHITE PAPER ON ATTACHMENT Z

## I. Background

Over the past year, the CAWG meetings have focused on Attachment Z from the perspective of what changes are needed to help promote investment in transmission upgrades that reduce congestion and result in lower cost, wholesale electricity supply to load-serving entities and ultimately to end-use consumers. For purposes of this white paper, transmission upgrades built to reduce congestion and lower the cost of electricity supply are considered Assigned Upgrades that are either directly assigned all or in part to the Transmission Customer or a Project Sponsor.[1] The key component of Attachment Z is the ability of an entity that has been directly assigned the costs of a transmission upgrade ("Assignee" to the "Assigned Upgrade") to receive revenue credits from additional use of these upgraded transmission facilities. Moreover, because it can be difficult and very costly on a per unit basis to construct small additions to the transfer capability of the transmission system, Attachment Z was initially designed to allow Transmission Customers not needing all of the capacity of the Assigned Upgrade to recover a portion of that cost[2] through revenue credits.

[1] The CAWG recognizes that transmission upgrades that are built to meet reliability standards can also reduce congestion and lower electricity supply costs, but these upgrades are required irrespective of their economic benefit and are not called "economic upgrades." Project Sponsor is definition 1.36a of the tariff; One or more entities that voluntarily agree to bear the cost of an Economic Upgrade. Transmission Customer is definition 1.45 of the tariff; Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.
Based on these definitions the Project Sponsor is NOT taking service and is NOT a Transmission Customer.

[2] The portion of cost eligible for recovery is the amount directly assigned to the transmission customer in excess of the stated SPP rate.

### A. Relationship of Revenue Credits to Investment in Economic Upgrades

In making a decision concerning investment in transmission facilities or accepting the direct assignment of the cost of upgrades to lower the cost of wholesale electricity supply, Transmission Customers and potential Project Sponsors would be comparing these costs to a stream of benefits they expect to receive from the expanded transmission capacity. These benefits could be in the form of either: 1) direct load benefits in the form of lower-cost purchases of power; or 2) direct generator benefits in the form of expanded sales of power. Both of these forms of benefits could reduce the cost of electricity supply for end-users.

Attachment Z provides an additional stream of revenues to be added to the cost/benefit calculation – revenue credits from others using the capacity of the facilities provided by the Assigned Upgrade. Having this additional stream of revenues available to the calculus of such decisions is critical to providing correct price signals and incentives

### B. Various Forms of Assigned Upgrades

Assigned Upgrades to the transmission system can be associated with either short-term (hourly, daily, weekly or monthly), mid-term (yearly up to 5 years) or long-term (5 years or longer) transactions for electricity supply.

Five years is used as a separation between long-term and mid-term because contracts for power supply that are 5 years or longer are eligible for regional cost allocation for new or changed designated resources to serve load. Even in the case of long-term contracts, if the cost of the upgrades needed to deliver power from a new or changed designated resource exceeds $180,000/ MW, the excess that is not currently eligible for regional cost allocation would be considered an Assigned Upgrade and the Assignee would be eligible to receive revenue credits on that directly assigned cost.

To obtain transmission service for either long-term or mid-term contracts, a Transmission Customer would either be subject to "or" pricing if the transmission service requested is Point-To-Point (PTP), or to "and" pricing if the Transmission Customer is a network service customer not wanting to take additional PTP transmission service from the generation source. In either case, if the Transmission Customer pays more than the SPP transmission rate, as the Assignee, the Transmission Customer would be eligible to receive revenue credits on that directly assigned cost.

The CAWG was concerned about how ~~a~~Assignees using Assigned Upgrades for the purposes of short term transactions would be ~~compensated~~protected. At one of the CAWG meetings a presentation was made regarding the flexibility a Transmission Customer taking long-term PTP transmission service would have under the SPP tariff.[3] Assignees evaluating electricity cost savings associated with short-term transactions may want to reserve firm PTP transmission service for one-year or longer to protect their use of the Assigned Upgrade.[4]

The CAWG also recognizes that assignees may not want to explicitly take PTP transmission service, but instead may simply want to sponsor the upgrade and participate in the SPP Energy Imbalance Market.

**C. Structure of the Attachment Z White Paper**

The remainder of this white paper is divided into two sections: Section II - Recommendation of the CAWG for changes to Attachment Z; and Section III – Alternative Resolutions for Unresolved Issues related to Attachment Z. In the

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[3] That presentation is included as an attachment to this white paper.

[4] Under proposed Order 888 reform, the FERC is requiring at least a 5 year reservation in order to be eligible for roll-over rights. If this change is implemented, it may be necessary to protect an investment in an economic upgrade designed for short-term electricity supply cost savings for the transmission customer to request a 5-year reservation for point-to-point transmission service.

recommendation Section II, a brief explanation of the reason for the recommendation will be presented. In Section III, details of discussion related to proposed alternative resolutions are presented.

## II. Recommendations of the CAWG for Changes to Attachment Z

### A. Project Sponsors

Project Sponsors are defined as those entities that request transmission upgrades be built, are willing to have the costs of the transmission upgrades directly assigned to them, but do not request transmission service to be taken from the Assigned Upgrade. Introducing the concept of a Project Sponsor not taking transmission service from the Assigned Upgrade requires some changes to be made to Attachment Z as it was originally drafted to provide an aggregate study process and revenue credits for Transmission Customers being directly assigned upgrade costs when such upgrades are needed in order to grant their requests for transmission service.

1. Absent any corresponding request for transmission service, should Project Sponsors be allowed to request and be directly assigned the costs of network upgrades? **CAWG Recommendation: YES.** This implies that Attachment Z should be divided into two distinct parts:

   Part I: Aggregated Study Process for Transmission Service Requests.

   Part II: Revenue Credits from Subsequent Transmission Use of an Assigned Upgrade for Assignees (both Transmission Customers and Project Sponsors).

2. Do any changes need to be made to Attachment Z regarding the aggregate study process? **CAWG Recommendation: YES**, there are several problems with the current aggregate study process that are listed

below. Possible resolutions to these problems are presented in Section III.

a. With respect to the aggregate study process, the current version of Attachment Z only refers to requests for transmission service. This would exclude Project Sponsors that are not requesting transmission service from participation in the aggregate study process as a way to determine whether or not there are transmission service requests that would benefit from the upgrade and thereby share in the cost of the upgrade.

b. A concern was expressed about speculative projects being submitted into the aggregate study process by Project Sponsors. Whether speculative projects are submitted in the form of transmission service requests or by Project Sponsors, the CAWG recognizes that such requests tend to bog down the aggregate study process and there appears to be a need for a separate process for evaluating speculative or competing projects, e.g., transmission service for bids from competing resources. However, studying these projects separately may lead to erroneous conclusions.

c. The aggregate study process has required a significantly long time to reach a conclusion as restudy is required every time an additional transmission service request decides not to proceed.

3. Should the direction of the impact of subsequent requests for transmission service matter in determining the eligibility of the Assignee to receive revenue credits? **CAWG Recommendation:** No. Instead of using the direction of a request, the focus should be, “could the new service have been provided without the upgrade?” If it could, then no revenue credits should be received. If it could not, then revenue credits should be received by the Assignees. The overriding principle should be whether the upgrade makes it possible to provide the requested service. As with the current version of Attachment Z, this recommendation does not apply to the category 3 power devises.

4. Should Project Sponsors be allowed to subsequently request transmission service and receive revenue credits? **CAWG Recommendation: YES**, this should be a viable alternative. In this situation, the Project Sponsor

would receive revenue credits from the payments received by SPP for the Project Sponsor’s subsequent request for transmission service.

a. Short-term PTP transmission service can be used by the Project Sponsor for bilateral transactions that use the Assigned Upgrade.
b. Long-term PTP transmission service can also be requested by the Project Sponsor at a subsequent time that uses the Assigned Upgrade. For example, a later request for long-term PTP transmission service could involve a new or changed DR.
c. A Project Sponsor that is a NITS customer may subsequently request a new DNR that uses the Assigned Upgrade.

5. Should Project Sponsors be allowed to make a lump sum payment to the TO for the Assigned Upgrade? **CAWG Recommendation: YES**, the CAWG understands that, whatever the form of the payment (e.g., revenue requirements over the asset life or a lump sum payment), a multi-party agreement will be required, involving the Project Sponsor(s), the Transmission Owner(s) and the SPP. The CAWG recommends that the SPP include standard forms for such agreements in its Business Practices. However, the SPP should offer a standard payment such as revenue requirements over the asset life, and any alternative payment method should be a contractual arrangement negotiated between the Project Sponsor, SPP and the TO.

6. Should Attachment Z continue to place a limit on the revenue credits for which the Project Sponsor is eligible? **CAWG Recommendation: YES**

a. The current form of Attachment Z limits revenue credits to payments for that portion of directly assigned costs above the standard rates for transmission service; e.g., either through “or” pricing for PTP service or through “and” pricing for Network Integrated Transmission Service (NITS) . A Project Sponsor would be entitled to receive the full amount of the Assigned Upgrade in revenue credits.

b. When a limit is placed on the amount of revenue credits received, the tariff must also allow for accumulation of the difference between that limit and revenue credits actually received, including interest. If this occurs, it must be clear that this accumulated amount is still a limit, not an amount due to the Project Sponsor at the end of some period of time.

c. The tariff should also include a limit on the time over which revenue credits can be received. This length of this period of time is an unresolved issue that is discussed in Section III.

**B. Subsequent Transmission Use of Assigned Upgrades in the Form of Requests for New or Changed Designated Resources.**

Subsequent transmission requests for new or changed Designated Resources (DRs) that qualify for Base Plan Funding under Attachment J and that impact/use Assigned Upgrades provide revenue credits to the original Assignee in the current version of Attachment Z. Transmission requests involving DRs that qualify for Base Plan Funding include both:

a) NITS requests for new or changed DNRs; and

b) PTP requests for new DRs.

However, the current version of Attachment Z does not separate out requests for new or changed DRs from other transmission requests that impact Directly Assigned Network Resources.

1. In revisions to Attachment Z, should subsequent transmission requests involving new or changed DRs be set out as a separate category for making payments to Assignees of Assigned Upgrades? **CAWG Recommendation: YES.** This subsequent use of transmission directly involves the application of Attachment J with the potential for Base Plan Funding being used for revenue credits, and therefore needs to be kept distinct from other forms of transmission service requests that impact Assigned Upgrades. More specifically, Attachment J requires an

assignment of costs for upgrades to requests for a new or changed DR, and the manner in which this cost assignment applies to the requestor of the new or changed DR is unique to Attachment J.

2. For purposes of Attachment J determinations, what costs from Assigned Upgrades should be included as attributable to subsequent requests for new or changed DRs? **CAWG Recommendation:** The costs from Assigned Upgrades that should be attributable to subsequent requests for DRs should include:

   (a) * (b) for Project Sponsor's Assigned Upgrades; or
   (a) * (c) for Transmission Customer's Assigned Upgrades

   Both calculations are illustrated in Appendix A.

   a. The original cost of the Assigned Upgrades. Whether or not accumulated depreciation over the period of time that these upgrades were in service should be subtracted from the original cost of the Assigned Upgrade is an unresolved issue that is discussed in Section III.

   b. The MW impact of the new or changed DR associated with a Project Sponsor's Assigned Upgrade that could not have been provided absent the Assigned Upgrade, as a percent of the smaller of the incremental MW transfer capacity created by the upgrade in either direction (denominator). ~~greater of either:~~
   ~~(1) The incremental MW transfer capacity created by the upgrade in the direction of the increased transfer capability associated with the Assigned Upgrade; or~~
   (1) ~~The sum of absolute value of the incremental MW impacts on the Assigned Upgrade which could not have been provided without the Assigned Upgrade.~~

   If the sum of MWs from new transmission service that could not have been provided absent the Assigned Upgrade exceeds the denominator calculated above, then the denominator would be adjusted to equal the sum of all MW impacts from new transmission service.

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   c. The MW impact of the new or changed DR associated with a Transmission Customer's Assigned Upgrade that could not have been provided absent the Assigned Upgrade, as a percent of subsequent new transmission service, where new transmission service includes the transmission service of the original Assignee plus any subsequent transmission service that impacts the Assigned Upgrade. ~~the sum of the absolute value of the incremental MW impacts on the Assigned Upgrade which could not have been provided without the Assigned Upgrade.~~

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The current Attachment Z applies (a) for all subsequent PTP use of the Assigned Upgrade and (b) for all subsequent network service use. However, the distinction should not be based on whether subsequent use is for PTP or network service use, rather the distinction should be based on whether or not, at the time of the original request, the Assignee of the costs of the Directly Assigned Network Upgrade requested and is now receiving transmission service from the Assigned Upgrade or not. If the Assignee did not take transmission service at the time of the original request (Project Sponsor), then it is impossible for the percent impact to be based on a share of the total incremental MW impacts from transmission service being taken from the upgrade as the Project Sponsor is not taking any transmission service and would have a zero impact. Using the incremental MW transfer capacity created by the upgrade is an alternative calculation that gives the same result as incremental MW impacts from transmission service sold when the total quantity of incremental MW impacts from transmission service sold are equal to the transfer capacity created by the transmission upgrade.

The primary reason for using percent of MW impacts from transmission service sold is to put all subsequent transmission service use of the upgrade on an equal basis with prior transmission service uses of that same upgrade. This will help to encourage potential co-sponsors not to wait until after the upgrade is completed to request desired transmission service in hopes of obtaining such service at a lower cost than if they had co-sponsored the upgrade.

3. Do the revenue credits apply only to the Assignee of the Assigned Upgrade or do they also apply to subsequent Transmission Customers who are paying for a portion of the upgrade through revenue credits? **CAWG Recommendation:**

   a. If the original Assignee is a Transmission Customer, then revenue credits from subsequent Transmission Customers are shared among the original Assignee and all previous Transmission Customers paying revenue credits. The sharing of revenue credits is allocated on a pro-rata basis of their MW impacts on the Assigned Upgrade.

   b. If the original Assignee is a Project Sponsor, then all revenue credits are assigned to the Project Sponsor up to the point that

      1) the sum of assigned costs to subsequent Transmission Customers equals 100% (see Appendix A), or alternatively

      2) the Project Sponsor is fully compensated (discuss meaning).

      If there is subsequent transmission service that is responsible to pay revenue credits, then those revenue credits are shared among all previous Transmission Customers paying revenue credits on a pro-rata basis of their MW impacts on the Assigned Upgrade.

4. Should the costs from Assigned Upgrades attributable to new or changed DRs be subject to the safe-harbor provision of Attachment J? **CAWG Recommendation: YES.** The issue here is whether or not a request for long-term PTP service involving a DR should be directly assigned any costs associated with transmission facilities that are already in place. In

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**Formatted:** Indent: Left: 1", First line: 0", Space Before: 0 pt this context, keep in mind that any request for DRs that does not meet either the safe-harbor provision or the conditions of Attachment J and does not receive a waiver can be directly assigned costs associated with upgrades needed to grant the request. In its approval of Attachment Z, the FERC determined that Network Service that impacts the Assigned Upgrade should pay revenue credits to the Assignee of the costs of the Assigned Upgrade. Clearly such an impact from a NITS customer could occur through a request for a new or changed DNR. The CAWG recommendation is that new or changed DRs requested through PTP service should be treated in a comparable manner.

a. The $180,000/MW cap should apply to all requests for new or changed DRs, whether through NITS or PTP transmission service.
b. The cost from already constructed Assigned Upgrades should be included along with the costs of any additional upgrades needed to grant this transmission service.
c. If the $180,000/MW cap is exceeded and a waiver is not granted, then the amount of the excess should be distributed in proportion to the costs of each transmission upgrade assigned to the DR request, including both Assigned Upgrades and any new upgrades required.

5. Should "higher of" pricing apply to subsequent requests for a new or changed DR through PTP service? **CAWG Recommendation: YES.** If the costs directly assigned to a Transmission Customer requesting a DR through PTP service exceed the PTP rate, then that customer should be responsible for those costs.

a. Applying Attachment J in conjunction with Attachment Z determines the amount of cost going into Base Plan Funding and the amount of costs (if any) that would be directly assignable to the TC for PTP service.
b. Any cost directly assignable to the PTP TC would then be compared to the tariffed rate for PTP service by applying usual "or" pricing procedures.

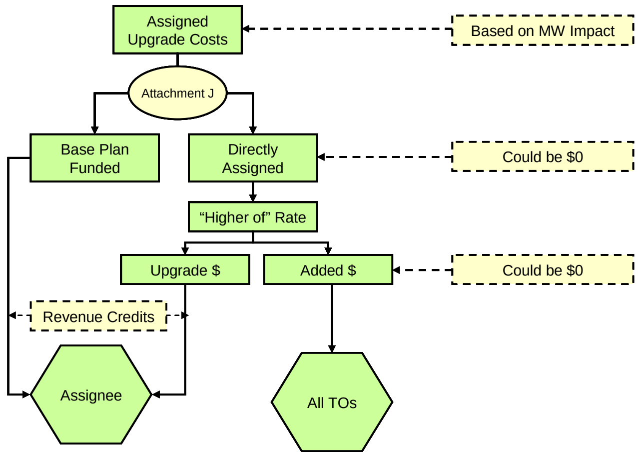
- Customer will always pay at least the PTP rate.
- If costs (above those included in Base Plan funding) are lower than the PTP rate, then the TC pays the PTP rate.
- If costs (above those included in Base Plan funding) are higher than the PTP rate, then the TC pays the PTP rate plus an excess above that rate.

6. What should be the dollar flows related to subsequent DR through PTP service using an Assigned Upgrade? **CAWG Recommendation:** See Appendix B for examples of all the possibilities listed below.

   The Assignee continues to pay for the cost of the Assigned Upgrade.

   - Cost of Assigned Upgrades is assigned to subsequent PTP TC based on MW impacts.
   - Revenues from subsequent PTP DR Service
     - Rates via Base Plan Funding for Assigned Upgrades go to SPP and are distributed to the Assignee. If Base Plan Funding covers all the costs, then the Assignee is not entitled to any additional revenue credits from the subsequent Transmission Customer. The subsequent Transmission Customer pays the PTP rate and the revenues are distributed to Transmission Owners.
     - If Base Plan Funding does not cover all the upgrade costs, then the subsequent Transmission Customer is directly assigned whatever costs are not covered, and the PTP "higher of" rate applies.
       - If the "higher of" rate is the PTP rate, then that portion of the PTP rate that covers transmission upgrade costs will be paid back to the Assignee's share of upgrade costs not covered by Base Plan Funding. The remaining revenues are distributed to Transmission Owners.
       - If the "higher of" rate is above the PTP rate, then all of the "higher of" rate is applied to cover transmission upgrade costs which include the Assignee's share of upgrade costs not covered by Base Plan Funding. There are no remaining revenues to distribute to Transmission Owners.

Diagram of Dollar Flows for New or
Changed DR Through PTP Service



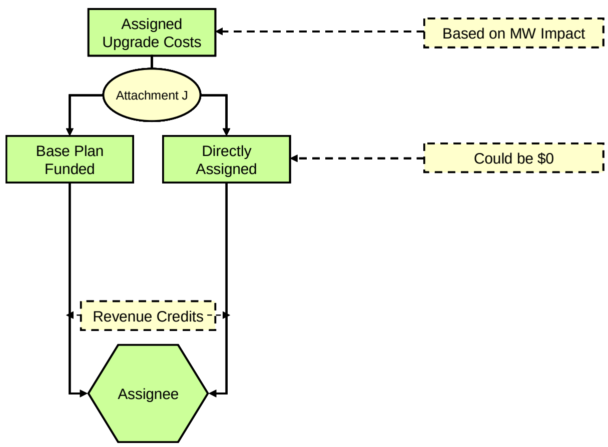

7. Should any change to Attachment J be made concerning a DNR request by a NITS customer that results in a form of "and" pricing? **CAWG Recommendation: NO.** Currently, under Attachment J, NITS customers requesting new or changed DNRs are subject to direct assignments of transmission upgrade costs as indicated below.

- When the assigned costs of the upgrades exceed the safe harbor limit of $180,000/MW a portion of the assigned costs of the upgrade above $180,000/MW are directly assigned to the NITS customer, unless a waiver is granted.
- To qualify for Base Plan funding, the DNR request must equal or exceed 5 years and total capacity cannot exceed 125% of forecasted peak demand. Otherwise, the NITS customer must either receive a waiver or pay for at least a portion of the cost of upgrades required to meet its DNR request.

8. What should be the dollar flows related to subsequent DNR through NITS service using a Assigned Upgrade? **CAWG Recommendation:** ~~See Appendix C for examples of all the possibilities listed below.~~

- Assignee continues to pay TO for the cost of the Assigned Upgrade.
- Cost of Assigned Upgrades are assigned to subsequent NITS customer based on MW impacts.
- Revenues from subsequent NITS DNR Service:
  - Rate via Base Plan Funding for Assigned Upgrades go to SPP and are distributed to the Assignee.
  - Any Excess above Base Plan Funding paid by NITS customer also goes to the Assignee.

Diagram of Dollar Flows for New or Changed DNR through NITS




**C. Subsequent Transmission Use of Assigned Upgrades by New or Changed System Load.**

In the previous section subsequent use of Assigned Upgrades associated with new or changed Designated Resources was discussed separately from other uses because these subsequent transmission requests are eligible for Base Plan Funding which provides a source of revenues to pay the revenue credits. In addition, there are reliability upgrades included in the SPP transmission plan that are eligible for either Base Plan Funding or to be included in the Transmission Owner's zonal rate. These upgrades do not involve subsequent requests for transmission service, but are associated with reliably meeting system load from currently approved DRs. Since upgrades needed to support approved new or changed DRs are already taken into account through the transmission request process, the purpose of the SPP transmission plan is to ensure that the transmission system can continue to provide reliable transmission service to system load. In this context, new or changed system load refers to situations where load growth has occurred in such a way that additional upgrades are needed to meet ERO[5] standards and SPP reliability criteria. In addition, Transmission Owners may have planning standards more stringent than ERO standards and SPP criteria, in which case upgrades may be required from new or changed load that results in associated costs being rolled into the Transmission Owner's zonal rate. Thus, either through Base Plan Funding or through Transmission Owners' zonal rates, there is a source of revenue to provide Assignees of Assigned Upgrades costs with revenue credits, where appropriate.

1. Should Assigned Upgrades that displace or defer reliability upgrades that would otherwise be needed result in reduced costs for the Assignees of the costs of the Assigned Upgrades? **CAWG Recommendation: YES**, to the extent that the reliability upgrades appear in the SPP Board approved plan at the time that the request for the Assigned Upgrades is approved. The cost of these reliability upgrades should be removed from the costs assigned to the Assignee. This is consistent with the current Attachment J that requires costs of reliability upgrades that are deferred or displaced by other transmission upgrades not be directly assigned, but instead are Base Plan funded.

2. Should subsequent use of Assigned Upgrades by "New Load" of a Transmission Customer result in revenue credits to the Assignees of the

[5] Electric Reliability Organization.

costs of the Assigned Upgrades? **CAWG Recommendation: YES.** It appears from the FERC Order on Attachment Z that if “New Load” associated with NITS impacts the Assigned Upgrade, the Assignee should receive revenue credits. A discussion of how SPP should make the necessary calculations to provide the revenue credits is included in Section III.

a. Clearly the addition of a large, new load would qualify, but there is no designated/arbitrary megawatt floor in the tariff.
b. In addition, it would appear that it shouldn’t make any difference whether there is only one customer or multiple customers that account for the new load.
c. In addition, it would appear that it shouldn’t make any difference whether the new load comes from existing customers or new customers.

**D. Subsequent Transmission Use of Assigned Upgrades by New PTP Transmission Service Other Than New or Changed Designated Resource.**

The previous two sections dealt with subsequent use of Assigned Upgrades associated with transmission requests for serving native load (i.e., new/ changed designated resources or new/ changed loads). In addition to these requests for transmission service to serve load from designated resources, there may be requests for PTP transmission service not related directly to serving load from designated resources. For purposes of this portion of the white paper, these subsequent requests for PTP transmission service are separated between short-term (less than one year) and long-term (more than one year).

Short-term requests for PTP transmission service are simply accepted or rejected by the SPP based on available transmission capability. There is no question of upgrades to meet these requests. This is not true of requests for long-term, PTP transmission service, where the length of term may require an upgrade in order to meet the request. It appears that upgrades could also be required for mid-term (over 1 year, but less than 5 years) requests for PTP transmission service even if the FERC implements the recommendation to limit roll-over rights to requests of 5 years or greater. At this time, it does not appear that limiting roll-over rights to requests involving more than 5 years would impact the following CAWG recommendations.

The current form of Attachment Z requires subsequent short-term PTP requests for transmission that impact Assigned Upgrades to provide revenue credits to the entities that have been directly assigned these costs. The requirements for receiving such revenue credits and the form of these revenue credits are as follows:

- Must impact the Assigned Upgrades involved in the same direction as the initial overload.
- This MW impact is to be recalculated each month.
- The calculation for such revenue credits included in the existing Attachment Z is (MW impact)*(Applicable PTP rate)
  - √ MW Impact = (% Distribution Factor)*(MW Transmission Service)
  - √ PTP rate = the applicable rate paid by the subsequent TC.

1. Should any changes be made to Attachment Z regarding the calculation of revenue credits from subsequent short-term PTP requests for transmission that impact Assigned Upgrades? **CAWG Recommendation: Yes, see Part II.A.3 and Part II.B.2**.

2. Should any changes be made to Attachment Z regarding the calculation of revenue credits from subsequent long-term PTP requests for transmission that impact Assigned Upgrades? **CAWG Recommendation: YES.** It should be clear in Attachment Z that requests for long-term PTP service with and without a new or changed DR should be treated on a comparable basis.

a. A request for PTP service that does not include a new or changed DR should include a direct assignment of costs from the Assigned Upgrade that is then included in SPP's calculation of "or"/"higher of" pricing for that request. **While comparability is a strong argument in favor of this recommendation, there is another alternative to this issue that is discussed in Section III.D.**

b. The calculations in the current Attachment Z require the SPP to recalculate the MW impact on the Assigned Upgrade for all PTP transmission service on a monthly basis. This is not consistent with the calculations made for long-term PTP service associated with a request for a new DR, where a one-time calculation of impact is made to determine the costs from the Assigned Upgrade that are, in essence, re-assigned to the subsequent request. In order to be consistent, the calculation of MW impacts for long-term PTP service should be made one time, whether or not the request involves a new or changed DR.

### E. Revenue Credit Streams Versus Lump-Sum Credits

1. Should Attachment Z consider a lump-sum credit to the ~~Project Sponsor~~ Assignee as an option in lieu of revenue credits when a portion of the revenue credits are coming from Base Plan Funding? **CAWG Recommendations:** Based on the following situations.

**NO when:**

a. Project Sponsor is making payments for the Assigned Upgrade over the asset life (e.g., 30 years). For example, assume a new DNR is approved and a portion of the cost of the Assigned Upgrade is Base Plan Funded. The dollar flows for the revenue credit case are:
   - Project Sponsor pays SPP monthly payment for Assigned Upgrade costs. SPP transfers payment to Transmission Owner.

- SPP bills appropriate Transmission Customers for rates associated with new DNR. A portion of the revenues collected go to Project Sponsor.
- In net, SPP credits the Project Sponsor's bill for revenues thereby reducing the Project Sponsor's net payment. SPP makes up the difference to the Transmission Owner from revenues received in rates for new DNR.

In effect, the Project Sponsor has received a lump-sum reduction to what is owed the SPP. But, this is different from receiving a lump-sum credit that would involve a one-time cash payment from SPP to the Project Sponsor.

b. The Network Transmission Customer funds the Assigned Upgrade when requesting a new DNR that exceeds the safe harbor limit of $180,000 per MW. The payment for the excess over the safe-harbor limit is made over the SPP standard payment period (e.g., 30 years). For example, assume a new DNR is approved and a portion of the cost of the Assigned Upgrade is Base Plan Funded. The dollar flows for the revenue credit case are identical to the previous example.

**YES, when:**

a. The Project Sponsor funds the Assigned Upgrade by paying the Transmission Owner the cost of the upgrade upfront. For example, assume a new DNR is approved and a portion of the cost of the Assigned Upgrade is Base Plan Funded. The dollar flows for the revenue credit case are:
- Project Sponsor pays SPP a monthly fee for operations & maintenance, including applicable payroll, payroll taxes, and property taxes of the Assigned Upgrade. SPP transfers payment to the Transmission Owner.
- SPP bills appropriate Transmission Customers for rates associated with new DNR. The appropriate portion of the revenues collected goes to the Project Sponsor.
- In net, SPP credits the Project Sponsor's bill for the revenues, thereby resulting in a net cash payment to the Project Sponsor.

Alternatively, the dollar flows for the lump-sum credit case are as follows:

- SPP collects from the Transmission Owner a lump-sum amount for portion of the Assigned Upgrade that is included in Base Plan Funding.
- SPP transfers this lump sum payment to the Project Sponsor and the amount of revenue credits for which the Project Sponsor is eligible is reduced.
- SPP collects from the Transmission Customers for rates associated with the new DNR.
- Transmission Owner receives revenues from SPP for the lump-sum payment.

- The Project Sponsor continues to make monthly payments for operations & maintenance, including applicable payroll, payroll taxes, and property taxes.

b. The Transmission Customer funds the Assigned Upgrade by paying the Transmission Owner the cost of the upgrade through "higher of" pricing over the term of the transmission service contract. For example, assume a new DNR is approved and a portion of the cost of the Assigned Upgrade is Base Plan Funded.

1) If the term of the transmission service contract is completed and the TC is no longer taking transmission service, the dollar flows are the same as in the previous case except that if the TC is no longer taking transmission service, there are no maintenance fees.
2) If the initial term of the transmission service contract is completed, but the TC continues to take transmission service, the dollar flows for the revenue credit case are as follows:
   - The customer pays the PTP rate and receives back in revenue credits a portion of the rate based on the MW impact on the Directly Assigned Network Facilities. The remaining revenues are distributed among TOs.
   - SPP bills appropriate Transmission Customers for rates associated with new DNR. A portion of the revenues collected go as a credit to the Transmission Customer who has funded the Assigned Upgrade.
   - The sum of revenue credits received by the Transmission Customer may or may not exceed the PTP rate.

   Alternatively, the dollar flows for the lump-sum credit case are as follows:

   - SPP collects from the Transmission Owner a lump-sum amount for the portion of the Assigned Upgrade that is included in Base Plan Funding.
   - SPP transfers this lump sum payment to the Transmission Customer and the amount of revenue credits for which the Project Sponsor is eligible is reduced.
   - SPP bills appropriate Transmission Customers for rates associated with new PTP service
   - Transmission Owner receives revenues from SPP for lump-sum payment.
   - The Project Sponsor continues to make monthly payments for the PTP rate absent revenue credits from the impact of the new DNR on the Assigned Upgrade.
3) If the initial term of the transmission service contract is not yet completed, the TC continues to take transmission service, and the dollar flows are the same as above without any revenue credits being received from the Transmission Customer's own impact on the Assigned Upgrade.

## III. Alternative Resolutions for Unresolved Issues Related to Attachment Z

### A. Aggregate Study Issues

**1. Proposals for evaluation of speculative or competing alternative transmission upgrade projects.**

a. The SPP should have a process separate from the aggregate study process that provides estimates of transmission upgrade costs for speculative or competing alternative transmission upgrade projects where it is understood that these estimates do not include any cost sharing possible from the aggregate study process. SPP could hire an outside consultant to perform these studies, and Transmission Customers requesting these studies be performed would pay the consultant fee.

b. However, the results could be misleading. If three alternatives are studied and one is selected on a stand alone basis, there is no assurance that this is the best choice on an aggregate basis. This separate procedure could only serve as a screening procedure. It still might reduce the number of speculative requests.

**2. Proposals for allowing Project Sponsors to benefit from the Aggregate Study process.**

a. Allow Project Sponsors to submit upgrades to which they are already fully committed to into the aggregate study process at any time prior to the in service date of the upgrade. Any transmission service request granted that requires the Project Sponsor's upgrade to be in place would share in the cost of the upgrade.

b. What should be the measure of commitment before Project Sponsors may submit proposed upgrades into the aggregate study process?

**3. Proposals for complete the Aggregate Study Process.**

a. Only allow a fixed number of iterations by requiring anyone signing up for the last iteration to pre-commit to the project. This would require SPP to provide information on worst case scenarios to those included in the second to last iteration prior to their making a commitment to participate in the last iteration.

b. Also consider a 180 day aggregate study process with a longer period for signing the letters of intent to encourage project commitment.

4. **For purposes of determining the cost of an Assigned Upgrade that is assigned to a subsequent request for transmission service, should accumulated deprecation be subtracted from the original cost?**

**YES.** Straight-line depreciation should be used in the calculation of accumulated depreciation and subtracted from the original cost of the Directly Assigned Network Resource. The reason for doing so is because the request for a new or changed DR may occur several years after the date at which the Assigned Upgrade is made, and there needs to be some mechanism to account for the age of the facilities in order that subsequent users are not overcharged for their use of older facilities. Straight-line depreciation is the most straight-forward method, and does not front load depreciation costs as would be the case for depreciation associated with levelized fixed charge rates.

**No.** While straight line depreciation maybe the most straight-forward method, it may not be consistent with the TO's determination of its fixed charge rate. Any depreciation method used must be consistent with the TO's method used to determine the payments being made by the Assignee or the credits paid to the Assignee.

5. **Should eligibility to receive revenue credits be for a fixed period (and if so, how many years), or should eligibility to receive revenue credits be for the service life of the asset, or should eligibility to receive revenue credits be based on the fixed charge rate used to determine the Assignee's Assigned Upgrade payment?**

   a. **Fixed Period – 30 Years**

The definition of "service life" in the draft Attachment Z2 reads as follows: "The time between the date electric plant is includible in electric plant in service, or electric plant leased to others, and the date of its retirement." This definition adopts an accounting life concept, in contrast with other types of service life such as the actual physical life, an engineering projection of physical life, and the tax life used for accelerated depreciation. Whereas accounting life and tax life both play major roles in determining standard revenue requirements, the physical life determines the period over which the facility is available to create revenue credits.

One advantage of using the accounting service life of a project to determine the maximum crediting period is that it gives the appearance of matching the potential credits with the period of time over which the Transmission Owner receives a return on the facility that is funded by the Project Sponsor or Transmission Customer. However, these time periods may not match in any event since the amortization period for revenue requirements purposes can be shorter than the accounting service life. In addition, there are other issues related to the service life that must be resolved if it is to be used as the basis for defining the period in which credits are applied.

Most upgrade projects are likely to include equipment assigned to multiple FERC accounts, with each account having a different service life, a different net salvage value, and a different depreciation rate. In such cases, a determination has to be made as to which equipment component's service life is used to determine the crediting period, and no single value may be accurate for the upgrade project in aggregate.

The service life used for accounting purposes can vary among companies, among regulatory jurisdictions, and among rate case orders. Should the crediting period vary depending on the Transmission Owner that constructs the project? Should the crediting period change if a rate order modifies the service life and the accompanying depreciation rate?

Both physical life and accounting life can be shortened by natural events, accidents, and technical obsolescence. Presumably, the crediting period must be shortened if a facility is retired early. In addition, the physical life sometimes can be extended by maintenance activity, capital additions, or both. These factors potentially create more uncertainty regarding the determination of service life.

As mentioned above, a possible alternative to utilizing service life as the maximum crediting period is to use a standard limit such as 30 years for all requested upgrades. A standard time limit would resolve some of the above questions associated with service life and would be simpler to administer. In addition, a standard crediting period may result in greater equity as a consistent time limit is applied to all upgrade projects, all Transmission Owners, and all Transmission Customers or Project Sponsors.

**b. Service Life**

Service life should be used for the period over which a Transmission Customer or Project Sponsor can receive revenue credits for the reasons below.

1) The Transmission Customer or Project Sponsor should receive revenue credits for all additional transmission service that could not be provided with out the upgrade; therefore as long as the project is in service the Project Sponsor should be eligible to receive revenue credits.

2) The excess that the Transmission Customer or Project Sponsor will pay over and above the base rates will be based upon the revenue requirements of the upgrade which will represent a composite ( dollar weighted) service life for the upgrade.

3) Transmission Owners do not use the same depreciation rates and choosing a standard term for revenue credits would be inconsistent with how the excess which is eligible for revenue credits is initially determined.

4) If an upgrade is removed from service earlier than originally anticipated that upgrade is no longer available to provide revenue credits whether service life or some other term is chosen.

5) The eligibility for credits should be consistent with the fixed charge rate used to determine the Assignee's Assigned Upgrade payment.

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**B. Subsequent Transmission Use of Assigned Upgrades in the Form of Requests for New or Changed Designated Resources.**

1. **In Attachment J, if a DNR request results in the load-serving entities reserve margin exceeding the 125% limit in the first few years after the resource comes on line, how should the customer be directly assigned any of the costs associated with upgrades required by the request ?** The purpose of the 125% reserve margin limit on DRs is as an upper bound to prevent gaming with respect to an individual load-serving entity from in essence reserving significantly more transmission than is needed to serve its load.

**ALTERNATIVES:**

a. The MW level by which the DR exceeds the 125% level as a percent of the DR request is used to directly assign the engineering &construction costs of any upgrades (current practice).

b. The costs of required upgrades equal to $180,000 times the request DR capacity that brings the reserve level to 125% will be base plan funded subject to the DR term of 5 years or longer. The costs in excess of this amount will be directly assigned.

c. The Transmission Customer is initially assigned the percent of costs by which the DR request exceeds the 125% reserve margin (see a. above). If the actual reserve margin falls below the 125% level after an initial period where that limit was exceeded, then the payments for the upgrades that were directly assigned to the Transmission Customer should then be Base Plan

Funded through the cost allocation mechanism. Moreover, once the reserve levels fall below the 125% level, the issue of reserving significantly more transmission than is needed to serve load goes away.

**C. Subsequent Transmission Use of Assigned Upgrades by New Network Load.**

**1. Would it make sense to include revenue credits from future reliability projects (those included at a later date in the SPP transmission plan) that would otherwise be needed "but for" the construction and availability of the Assigned Upgrades?**

**YES**, this is a case where the "but for" condition makes sense, at least to the extent that this can be done in the SPP planning process.

a. One way to do this is to exclude all Assigned Upgrades from the SPP base case to identify criteria violations and needed upgrades.

b. Then answer the question: which of the needed upgrades are displaced by existing Assigned Upgrades.

**NO.** Making the "but for" calculations in the SPP planning process could require extensive additional modeling. RTWG should obtain SPP input before going forward with the types of calculations that could be required for including revenue requirements for older projects.

**D. Subsequent Transmission Use of Assigned Upgrades by New PTP Transmission Service Other Than New or Changed Designated Resource.**

**1. Should the applicable PTP rate include "higher of" pricing via applicable cost from Assigned Upgrades?**

**YES**

a. Comparability to PTP service that includes a new or changed DR - Should be the same as for a request for DR through a request for long-term PTP service that impacts an Assigned Upgrade, and both should include an assigned portion of the costs in the calculation of the "higher of" price.

b. A request for long-term PTP service may (and is likely to) require additional upgrades. If the Assigned Upgrades are excluded from the "higher of" calculations, then a proper allocation of revenue credits to Project Sponsors will not result.

**NO**

a. Discourages sales of PTP service and will result in lower revenues.

b. Could potentially result in gaming by customers taking short-term rather than long-term PTP service.

## APPENDIX A
## EXAMPLES OF CALCULATION OF
## MW IMPACT FROM
## NEW TRANSMISSION REQUESTS

**Assumptions common to all examples:**

Assigned Upgrade increased the capacity of the existing flowgate by 500 MW in the A to B direction as well as in the B to A direction.

New transmission service request from Customer B has a 50 MW impact on the same flowgate and in the ~~same~~ A to B direction.

The original cost of the Assigned Upgrade was $16,000,000.

The Assigned Upgrade has been in service for 10 Years with a depreciation life of 40 years.

Calculation common to all examples: The net plant value of the Assigned Upgrade:

Original Cost – Accumulated Depreciation

$16,000,000 – (10/40)*($16,000,000) =

$16,000,000 - $4,000,000 = **$12,000,000**

**Example A: MW Impact as a percent of Incremental MW Capacity**

Additional Assumption: The Assignee that requested the Assigned Upgrade did so without requesting any transmission service; i.e., is a Project Sponsor.

Percent of MW capacity from the new transmission service:

50 MW % 500 MW = 10%

Cost of Assigned Upgrade allocated to Customer B:

$12,000,000 * 10% = **$1,200,000**

**Example A1: MW Impact from adding multiple new transmission service**

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In Example A, assume a customer C takes transmission service at the same time as Customer B and the impact on the Assigned Upgrade is 450 MWs. The cumulative impact of customers B and C now equals 500 MW, which is the denominator in the calculation being used to determine the percent of costs being allocated to new transmission service that impacts the Assigned Upgrade.

Customer B: $12,000,000 * 10% = $1,200,000

Customer C: $12,000,000 * 90% = $10,800,000

**Example A2: MW Impact from adding subsequent new transmission service**

Suppose a third Transmission Customer D takes transmission service subsequent to Customers B and C, and the impact on the Assigned Upgrade for Customer D is 100 MWs. The cumulative impact of customers B, C and D now equals 600 MW, which is greater than the denominator use in the calculations in examples A and A1. The question then, is what should Customer D be allocated in costs (for purposes of simplicity in the calculations, also paying in revenue credits), and who should receive those revenue credits?

First, the denominator used to calculate Customer D's share of costs has increased from 500 MW to 600 MW, which is the sum of the MW impacts on the Assigned Upgrade:

Customer D: (100 MW/600 MW) * $12,000,000 = $2,000,000

Second, revenue credits from Customer B and C still go to A (the Project Sponsor), however, if A is fully compensated, revenue credits from Customer D would not go to A but instead would go to Customers B and C in proportion to their MW impacts to each.

Customer B: (50 MW / 500 MW = 10%)*$2,000,000 = $200,000

Customer C: (450 MW / 500 MW = 90%)*$2,000,000 = $1,800,000

Third, notice that this reduces the costs allocated to Customers B and C to the same level they would have been had their percent allocation been based on a denominator of 600 MW:

Customer B:
$1,200,000 (to A) – $200,000 (from D) = $1,000,000
Where: (50/600)*$12,000,000 = $1,000,000

Customer C:
$10,800,000 (to A) – $1,800,000 (from D) = $9,000,000
Where: (450/600)*$12,000,000 = $9,000,000

**Example B: MW Impact as a percent of Incremental Transmission Service**

Additional Assumption: The customer that requested the Assigned Upgrade (Customer A) did so through a request for transmission service; i.e., is a Transmission Customer, and that transmission service uses 100 MWs of the 500 MWs of increased capacity on the flowgate

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Percent of incremental transmission service taken on the Assigned Upgrade by Customer B:

50 MW % (100 MW + 50 MW) =

50 MW % 150 MW = 33.3%

2. Cost of Assigned Upgrade allocated to Customer B:

$12,000,000 * 33.3% = **$4,000,000**

**Example B1: MW Impact from adding subsequent new transmission service**

Additional Assumption: In example B, assume that after the first new customer (Customer B) was granted transmission service, a second new customer (Customer C) is granted new transmission service with a 25 MW impact on the Assigned Upgrade in the same direction, A to B.

1. Percent of incremental transmission service taken on the Assigned Upgrade by Customer C.

   25 MW % (100 MW + 50 MW + 25 MW) =

   25 MW % 175 MW = 14.3 %

2. Cost of Assigned Upgrade allocated to

   Customer C: $12,000,000 * 14.3 % = **$1,714,286**

   Customer B: $12,000,000 * 33.3% = $4,000,000

**Example B2: MW Impact from adding multiple new transmission service**

Additional Assumption: In example B, assume that at the same time both Transmission Customers request transmission service – Customer B for 50 MW and Customer C for 25 MW.

1. Percent of incremental transmission service taken on the Assigned Upgrade by the new customers:

   Customer B: 50 MW % 175 MW = 28.6%

   Customer C: 25 MW % 175 MW = 14.3%

2. Cost of Assigned Upgrade allocated to new Transmission Customer:

   Customer B:$12,000,000 * 28.6% = **$3,428,571**

   Customer C:$12,000,000 * 14.3% = **$1,714,286**

**ExampleB3: Compare Examples B1 to ExampleB2**

Notice that Customer B is paying less in example B2 than he would be paying in example B1, simply because of the sequencing of the service request. To correct this problem, in example B2 Customer B along with Customer A should be eligible for revenue credits from Customer C. Thus in example B2, the distribution of revenue credits from Customer C between Customers A and B is:

1. Percent allocation of revenue credits between Customers A and B:

   Customer A: 100 MW % 150 MW = 66.7%

   Customer B: 50 MW % 150 MW = 33.3%

2. Allocation of Revenue Credits (Revenue Credits are treated the same as costs for the sake of simplicity) from Customer C to Customers A and B:

   Customer A: $1,714,286 * 66.7% = $1,141,857

   Customer B: $1,714,286 * 33.3% = $571,429

Notice that with this revenue credit from Customer C, Customer B is now paying in net the same amount as shown in Example D; i.e.,

$4,000,000 (to Customer A) - $571,429 (from Customer C) = **$3,428,571**

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# APPENDIX B
# EXAMPLES OF DOLLAR FLOWS FOR VARIOUS APPLICATIONS OF HIGHER OF PRICING FOR PTP SERVICE ASSOCIATED WITH A DESIGNATED RESOURCE

## Example 1: Basic Calculations

- The Attachment J assignment of costs to the new Transmission Customer from the Assigned Upgrade costs exceeds the safe-harbor provision of $180,000/MW.
- The excess over the safe-harbor limit are directly assigned to the new Transmission Customer.

| Example 1: Basic Parameters Assumed | | |
|---|---|---|
| Upgrade Original Cost | $65,000,000 | Gross Plant |
| Depreciation Life | 30 | Years |
| Accum. Depreciation | $6,500,000 | after 3 years |
| Cost Included | $58,500,000 | Net Plant |
| PTP Reservation | 100 | MW |
| Trans Serv Term | 5 | Years |
| PTP Service Charge | $1,200,000 | Assumed $1/kW/Month |
| % Distriburtion Factor | 20% | Impact on Upgrade |

| Attachment Z Calculation | | |
|---|---|---|
| Cost Included | $58,500,000 | Net Plant |
| Initial TC MW Impact | 40 | Assumed |
| New TC MW Impact | 20 | (%DF)*(MW Resrv) |
| Total MW Impact | 60 | Sum |
| % New TC | 33% | (New TC MW) / (Total MW) |
| New TC $ | **$19,500,000** | (New TC %) * (Cost Included) |

| Attachment J Calculations | | |
|---|---|---|
| Cost / MW | $195,000 | (New TC %) / (MW Resrv) |
| Safe Harbor Limit | $18,000,000 | (180,000/Mw) * (MW Resrv) |
| Eligible for BPF | **$18,000,000** | Min (New TC $, Safe Harbor) |
| Direct Assign | **$1,500,000** | (New TC$) - (Eligible for BPF) |

**Example 1: Dollar Flows**

**SPP Revenue Sources**

- BPF upgrade costs are collected through zonal rates per the cost allocation in Attachment J.
- The revenue requirements associated with these directly assigned costs to the new Transmission Customer are less than the PTP rate, resulting in the new Transmission Customer paying only the PTP rate.

| BPF Rate Calculations | | | |
|---|---|---|---|
| Eligible for BPF | $18,000,000 | | (180,000/Mw) * (MW Resrv) |
| Annual Revenues BPF | **$3,060,000** | 17% | Fixed Charge times BPF Costs |

| "Higher of" Rate Calculations | | |
|---|---|---|
| Direct Assign | $1,500,000 | (New TC$) - (Eligible for BPF) |
| Fixed Charge % | 32% | Calc for 5 yr. Trans Serv Resrv |
| Annual Cost | $480,000 | per year |
| PTP Service Charge | $1,200,000 | per year |
| Customer Pays Higher of | **$1,200,000** | Max (Annual Cost, PTP Serv Chrg) |

**SPP Revenue Payments**

- The original Transmission Customer receives all the revenues from the BPF.
- The revenues collected from the PTP rate are split between the original Transmission Customer (to cover the costs directly assigned to the new Transmission Customer) and the other Transmission Owners (TOs) per the standard SPP revenue distribution formula.

| | | Dollar Flows | |
|---|---|---|---|
| Payments to SPP | | $4,260,000 | |
| | FROM | | |
| | New TC | $1,200,000 | PTP Rate |
| | BPF | $3,060,000 | Rolled into Zonal Rates |
| Payments by SPP | | $4,260,000 | |
| | TO | | |
| | Initial TC | $3,540,000 | |
| | | $3,060,000 | From BPF Rates |
| | | $480,000 | Direct Assigned to new TC |
| | Other TOs | $720,000 | From PTP Rate - New TC |

### Example 2: Basic Calculations

- The Attachment J assignment of costs to the new Transmission Customer from the Assigned Upgrade costs exceeds the safe-harbor provision of $180,000/MW.
- The excess over the safe-harbor limit are directly assigned to the new Transmission Customer.

| Example 2: Basic Parameters Assumed | | |
|---|---|---|
| Upgrade Original Cost | $100,000,000 | Gross Plant |
| Depreciation Life | 30 | Years |
| Accum. Depreciation | $10,000,000 | after 3 years |
| Cost Included | $90,000,000 | Net Plant |
| PTP Reservation | 100 | MW |
| Trans Serv Term | 5 | Years |
| PTP Service Charge | $1,200,000 | Assumed $1/kW/Month |
| % Distriburtion Factor | 20% | Impact on Upgrade |

| Attachment Z Calculation | | |
|---|---|---|
| Cost Included | $90,000,000 | Net Plant |
| Initial TC MW Impact | 40 | Assumed |
| New TC MW Impact | 20 | (%DF)*(MW Resrv) |
| Total MW | 60 | Sum |
| % New TC | 33% | (New TC MW) / (Total MW) |
| New TC $ | $30,000,000 | (New TC %) * (Cost Included) |

| Attachment J Calculations | | |
|---|---|---|
| Cost / MW | $300,000 | (New TC %) / (MW Resrv) |
| Safe Harbor Limit | $18,000,000 | (180,000/Mw) * (MW Resrv) |
| Eligible for BPF | **$18,000,000** | Min (New TC $, Safe Harbor) |
| Direct Assign | **$12,000,000** | (New TC$) - (Eligible for BPF) |

**Example 2: Dollar Flows**

**SPP Revenue Sources**

- BPF upgrade costs are collected through zonal rates per the cost allocation in Attachment J.
- The revenue requirements associated with these directly assigned costs to the new Transmission Customer are greater than the PTP rate, resulting in the new Transmission Customer paying more than the PTP rate.

| **BPF Rate Calculations** | | |
|---|---|---|
| Eligible for BPF | $18,000,000 | (180,000/Mw) * (MW Resrv) |
| Annual Revenues BPF | **$3,060,000** | 17% Fixed Charge times BPF Costs |

| **"Higher of" Rate Calculations** | | |
|---|---|---|
| Direct Assign | $12,000,000 | (New TC$) - (Eligible for BPF) |
| Fixed Charge % | 32% | Calc for 5 yr. Trans Serv Resrv |
| Annual Cost | $3,840,000 | per year |
| PTP Service Charge | $1,200,000 | per year |
| Customer Pays Higher of | **$3,840,000** | Max (Annual Cost, PTP Serv Chrg) |

**SPP Revenue Payments**

- The original Transmission Customer receives all the revenues from the BPF.
- The revenues collected from the PTP rate all go to the original Transmission Customer to cover the costs directly assigned to the new Transmission Customer. Other Transmission Owners (TOs) receive no revenues from the new Transmission Customer.

| | **Dollar Flows** | |
|---|---|---|
| Payments to SPP | $6,900,000 | |
| FROM | | |
| New TC | $3,840,000 | PTP Rate |
| BPF | $3,060,000 | Rolled into Zonal Rates |
| Payments by SPP | $6,900,000 | |
| TO | | |
| Initial TC | $6,900,000 | |
| | $3,060,000 | From BPF Rates |
| | $3,840,000 | Direct Assigned to new TC |
| Other TOs | $0 | From PTP Rate - New TC |

## Example 3: Basic Calculations

- The Attachment J assignment of costs to the new Transmission Customer from the Assigned Upgrade costs are less than the safe-harbor provision of $180,000/MW.
- There are no directly assigned costs to the new Transmission Customer.

| Example 3: Basic Parameters Assumed | | |
|---|---|---|
| Upgrade Original Cost | $10,000,000 | Gross Plant |
| Depreciation Life | 30 | Years |
| Accum. Depreciation | $1,000,000 | after 3 years |
| Cost Included | $9,000,000 | Net Plant |
| PTP Reservation | 100 | MW |
| Trans Serv Term | 5 | Years |
| PTP Service Charge | $1,200,000 | Assumed $1/kW/Month |
| % Distriburtion Factor | 20% | Impact on Upgrade |

| Attachment Z Calculation | | |
|---|---|---|
| Cost Included | $9,000,000 | Net Plant |
| Initial TC MW Impact | 40 | Assumed |
| New TC MW Impact | 20 | (%DF)*(MW Resrv) |
| Total MW | 60 | Sum |
| % New TC | 33% | (New TC MW) / (Total MW) |
| New TC $ | $3,000,000 | (New TC %) * (Cost Included) |

| Attachment J Calculations | | |
|---|---|---|
| Cost / MW | $30,000 | (New TC %) / (MW Resrv) |
| Safe Harbor Limit | $18,000,000 | (180,000/Mw) * (MW Resrv) |
| Eligible for BPF | **$3,000,000** | Min (New TC $, Safe Harbor) |
| Direct Assign | **$0** | (New TC$) - (Eligible for BPF) |

**Example 3: Dollar Flows**

**SPP Revenue Sources**

- BPF upgrade costs are collected through zonal rates per the cost allocation in Attachment J.
- With no directly assigned costs to the new Transmission Customer, that Transmission Customer only pays the PTP rate.

| BPF Rate Calculations | | | |
|---|---|---|---|
| Eligible for BPF | $3,000,000 | | (180,000/Mw) * (MW Resrv) |
| Annual Revenues BPF | **$510,000** | 17% | Fixed Charge times BPF Costs |

| "Higher of" Rate Calculations | | |
|---|---|---|
| Direct Assign | $0 | (New TC$) - (Eligible for BPF) |
| Fixed Charge % | 32% | Calc for 5 yr. Trans Serv Resrv |
| Annual Cost | $0 | per year |
| PTP Service Charge | $1,200,000 | per year |
| "Higher of" Charge | **$1,200,000** | Max (Annual Cost, PTP Serv Chrg) |

**SPP Revenue Payments**

- The original Transmission Customer receives all the revenues from the BPF.
- The revenues collected from the PTP rate all go to other Transmission Owners (TOs) as the original Transmission Customer is fully compensated for the costs assigned out through Attachment J.

**Dollar Flows**

| | | |
|---|---|---|
| Payments to SPP | $1,710,000 | |
| FROM | | |
| New TC | $1,200,000 | PTP Rate |
| BPF | $510,000 | Rolled into Zonal Rates |
| | | |
| Payments by SPP | $1,710,000 | |
| TO | | |
| Initial TC | $510,000 | |
| | $510,000 | From BPF Rates |
| | $0 | Direct Assigned to new TC |
| | | |
| Other TOs | $1,200,000 | From PTP Rate - New TC |

SPP EIS Market Deployment Test Briefing

- RSC Meeting
- October 23, 2006



## Deployment Tests

- SPP held 12 deployment tests since August 1
- Accumulated 69 hours of market deployment
- Spanned all 24 hours of the day including peak hour, morning ramp, and evening drop-off periods
- Longest contiguous test was for 15 hours
- Peak load recorded during the tests - 31,216 MW
- Max. LIP was $3,324.25, min. LIP was $2,615.71
- 7 reserve sharing events
- 22 TLR events

## Deployment Test Metric Results since August 1

- **Metrics addressing generation following SPP deployment – passed all 12 tests**
- **Metrics addressing total number of CPS violations across footprint – passed 11 out of 12 tests**
- **Metrics addressing total number of CPS violations per BA – passed 5 out of 12 tests**
- **Metrics addressing market dispatch including constraint relief – passed 10 tests in which metric existed**





## Status of Critical Readiness Issues

- **LIP Volatility**
  - **Observed decreased volatility during October tests (max LIP of $377.26, min LIP of -$158.75)**
- **Short-term Load Forecasts**
  - **Improvement during October tests**
  - **Will monitor and make further refinements if necessary**
- **CAT/Constraint Manager**
  - **All critical fixes in place prior to October tests**
- **System Stability**
  - **Standby database has been tested and installed**
  - **Ability to recover in less than 1 hr. has been demonstrated**

## Future Deployment Tests

- **October 26**
- **November 1**
- **November 9**

Southwest Power Pool

# Unintended Consequences Update

**RSC Meeting**

**October 23, 2006**

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## Current Status

- **RTWG formed a Task Force (IZATF) to review options**
- **The Task Force has met multiple times and looked at various options**
  - **Two different mw-mile methods**
  - **Several different fixed allocations**
- **The Task Force is to report back to the RTWG so that the RTWG can bring a final recommendation to the MOPC, RSC and BOD in January.**

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Southwest Power Pool

## Another Issue

- The delay is causing another issue.
  - Identified Reliability Projects being held up while reviewing cost allocation.
  - Some of the projects are required to be built before several Transmission Requests can be granted.
  - RTWG voted unanimously to ask the BOD to approve the Reliability Project list so construction can start while the cost allocation issues get resolved.

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## Changes to Schedule 2

**RSC Meeting**

**October 23, 2006**

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## Reactive Power Compensation

- Ancillary Service 2
  - Order 888
  - Compensate Generators for producing Reactive power to support the transmission system.
  - Customer must purchase
  - Current SPP OATT only compensates TO's generators





## Approvals

- White paper presented in April
  - Approved by the MOPC
  - Approved by the BOD
- Sent to the RTWG for tariff language
  - SPP/Calpine Order released Sept. 27
  - Issues converting Whitepaper to the Tariff

**The RTWG Tried to "Pull a Tariff out of its Hat" and complete the Changes to Schedule 2 prior to the MOPC meeting.**

**It didn't quite work.**





## Current Status

1. **MOPC requested SPP to ask for an extension to file a compliance rate**
2. **RTWG has had four conference calls to work on Schedule 2**
3. **Schedule 2 language is 98% complete.**
4. **Still need to complete the impact analysis.**

# Regional State Committee

## OG&E, GSEC & Westar Waiver Requests

**October 23, 2006**

**Tulsa, Oklahoma**

## Tariff Requirements Attachment J (Page 1 of 4)

- **Factors to be considered in evaluating waiver requests:**
  - **There are insufficient competitive resource alternatives for one or more Transmission Customers;**
  - **In the event that the aggregate costs of a Network Upgrade exceed the Safe Harbor Cost Limit ("SHCL"),**
    - **(i) Those costs up to the level of the SHCL shall be classified as Base Plan Upgrade costs, and**
    - **(ii) Those costs that exceed the SHCL may be classified in whole or in part as Base Plan Upgrade costs taking into account the extent to which the duration of the Transmission Customer's commitment to new or changed Designated Resource exceeds the five-year commitment period set forth in paragraph III.B.1;**



## Tariff Requirements Attachment J (Page 2 of 4)

- **The five-year commitment period for the new or changed Designated Resource may be waived if:**
  - **(i) The associated Network Upgrade costs are significantly less than the SHCL; or**
  - **(ii) The associated Network Upgrades provide benefits to other Transmission Customers that would offset in less than five years any costs allocated to them as a result of the upgrade being classified as a Base Plan Upgrade;**
- **If a request for a waiver is received by SPP based upon other circumstances, such waiver request shall also be considered pursuant to the waiver process described in Section III.C.1. of Attachment J.**



## Tariff Requirements Attachment J (Page 3 of 4)

- **If the costs of the Network Upgrade(s) required for a new or changed Designated Resource are not eligible for classification as Base Plan Upgrade costs, the Transmission Customer may nevertheless request the construction of such upgrades.**
  - **In such event, the costs of such upgrades shall be allocated in accordance with Section V of Attachment J.**



## Tariff Requirements Attachment J (Page 4 of 4)

- **SPP Staff reviews each waiver request and makes a determination on a non-discriminatory basis whether a waiver should be granted based upon consideration of the factors described in Section III.C.2.**
- **SPP Staff provides a report and recommendation to the Markets and Operations Policy Committee ("MOPC") on each waiver request.**
- **The MOPC considers the waiver request and the SPP Staff's report and recommendation and provides its own recommendation to the SPP Board of Directors.**
- **Barring unusual circumstances, a valid waiver request will be reviewed and submitted to the SPP Board of Directors within <u>120 days</u> following receipt of the waiver request.**



## SUMMARY of OG&E WAIVER REQUEST

- **OG&E Waiver Request involves minor upgrades to local 138 and 69 kV lines and replacement of a 138/69 kV transformer.**
  - **OG&E reservation 1032973 studied by SPP in SPP-2006-AG1-AFS-4.**
  - **OG&E provided SPP with 8 MW as net dependable capacity of Centennial Wind Farm.**
  - **<u>May 19, 2006</u> - OG&E submitted waiver request based on service life of 25 years (120-day deadline was September 16, 2006).**
  - **<u>August 29, 2006</u> – SPP staff requested additional information to support waiver request.**
  - **<u>September 25, 2006</u> – OG&E provided additional information on waiver request.**
  - **SPP Staff submitted recommendation to MOPC.**
  - **MOPC's motion to reject SPP's recommendation failed with 45.8% support.**

## SUMMARY of GSEC WAIVER REQUEST

GSEC's Waiver request involves regional upgrades to install more than 600 miles of 345 kV lines, related substations and auto transformers and numerous 138 and 69 kV upgrades throughout Kansas, Oklahoma and Texas.

- GSEC reservation 1034404 studied by SPP in SPP-2006-AG1-AFS-3.
- May 19, 2006 - GSEC submits waiver request based on insufficient competitive resource alternatives and service life of 30 years.
- August 9, 2006 – GSEC withdrew waiver request for 1034404 and requested that the waiver request be transferred to 1090388.
- August 29, 2006 - SPP staff requested additional information to support the waiver request.
- September 25, 2006 - GSEC provided additional information in response to SPP's request dated August 29, 2006.
- Submittal to SPP Board of Directors to meet the 120-day deadline per the tariff is due December 7, 2006.
- Reservation 1090388 is currently being studied by SPP; study is NOT complete.

7

## SUMMARY of WESTAR WAIVER REQUEST

Westar waiver request involves replacement of old 138 kV lines with new 345 kV line from Rose Hill to Sooner.

- October 13, 2006 – Westar submits waiver request based on 20 year service life and based on benefits to other customers that would offset costs allocated to them in less than five years.
- Westar reservation 1086655 studied by SPP in SPP-2006-AG2-AFS-2.
- Submittal to SPP Board of Directors to meet the 120 days per the tariff is due February 10, 2007.
- Westar reservation 1086655 is currently being studied by SPP; study is NOT complete.
- SPP staff has not yet begun review and analysis of the Westar waiver request.

8

## MOPC Actions October 10-11, 2006

- Rejected SPP Staff's recommendation on OG&E waiver request.

  Failed with 45.8 % support
- Directed SPP Staff to present and discuss its recommendation in addition to the criteria used to evaluate a waiver to the CAWG for their direction and recommendation prior to the next MOPC meeting.
- Recommendation to the BOD that unusual circumstances exist with the OG&E waiver and the 120 day deadline should be extended to the end of January, 2007.
- Westar waiver not considered at MOPC as request not received until October 13, 2006.

9

## Next Steps

- OG&E waiver awaiting action since study is complete and service agreement is pending.
- GSEC waiver amount not final.
  - 2006-AG2-AFS-2 posted October 6th.
  - At least one more restudy to be required.
  - Preliminary Aggregate Study results indicate that no additional SHCL funding will be required due to the displacement of reliability upgrades by 4 years from 2015 to 2011.
  - SPP has noted verbal withdrawal of waiver request.
- Westar waiver is being reviewed by SPP Staff.

10

## Conclusions

- Coordination with CAWG/RSC.
- Definition of waiver criteria.
- Certainty of the outcome of waiver process.

11