Regional State Committee / Southwest Power Pool, Inc.
COST ALLOCATION WORKING GROUP MEETING

January 4, 2008
AEP Dallas Offices
Renaissance Towers
1201 Elm Street

• A G E N D A •

8am – 1pm
CAWG Participant Number and Code -
Toll: 203-320-8823
Participant: 113358

1. Annual Work Plan ................................................................. Les Dillahunty
2. RSC Agenda ................................................................. Les Dillahunty
3. EDE & AEP Waivers ............................................................. Jay Caspary

Break, 15 minutes

4. Wind Generation Base Plan Funding Policy Discussion ...................... Jay Caspary
5. Discussions on Changes to Cost Allocation for Designated Wind Resources ................................................................. Larry Holloway/Bary Warren

LUNCH, 12:30

7. Survey Results ................................................................. Les Dillahunty
CAWG Work plan -

1. Policy for Cost Allocation for Economic Upgrades and Portfolio Development

2. Review of Aggregate Study and Generation Interconnection improvements

3. Initiate the required regional allocation factor and zonal allocation methodology

4. Waivers

5. Capacity accreditation

6. Resource Adequacy

7. STEP/EHV/OEPTTF and other special studies review

8. Seams/inter-regional cost allocation


10. EIS market review
AGENDA

ANNUAL MEETING *
Monday, January 28, 2008
1:00 pm- 5:00 pm
Hyatt Regency – Town Lake
Austin, TX

1. CALL TO ORDER

2. PRELIMINARY MATTERS
   a. Declaration of a quorum
   b. Adoption of July 23 and October 29, 2007 Minutes

3. UPDATES
   a. RSC Financial Report
   b. Other RSC officer reports
   c. FERC
   d. SPP
   e. RE

4. BUSINESS MEETING
   a. Cost Allocation Working Group..............................................................Dr. Mike Proctor
      • Concepts Paper on Economic Upgrades
      • Wind Generation Base Plan funding Policy Discussion
      • Empire District Electric and American Electric Power Waiver Request (Action Item)
   b. Overview of Board of Directors and Stakeholders Survey............................Michael Desselle
   c. STEP 2007 & EHV Report.................................................................Jay Caspary
   d. EPRI Report – The Power to Reduce CO₂ Emissions Highlights .................Les Dillahunty
   e. Project Tracking (written report)

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

6. ADJOURNMENT
Empire Waiver Request

November 2007
Empire Waiver Request

- The following SPP recommendation based on current SPP Tariff
- SPP is aware of policy issues raised by this waiver
- Policy decisions under consideration by CAWG/RSC, if approved, could significantly impact this recommendation

Review of EDE Request

- EDE reservation 1222640 studied: SPP-2007-AG1-AFS-3, 4, 5 & 6
- EDE requesting 100 MW from Cloud County Wind farm
- Base plan funding maximum calculated: 10 MW x $180,000/MW = $1,800,000
- Aug. 2007 Letter – EDE requests waiver
- Tariff required submittal by Dec 21, 2007
- Nov. 2007 letter - EDE asked SPP to reconsider and issue revised recommendation for discussion by CAWG, RSC, MOPC, BOD (Jan. 2008)
Attachment J Section B.3

- Cost of Network Upgrades associated with new or changed Designated Resource shall be classified as Base Plan Upgrades if they are less than or equal to $180,000/MW times the lesser of:
  - (a) the planned maximum net dependable capacity applicable to the Transmission Customer or
  - (b) the requested capacity (the “Safe Harbor Cost Limit”)

Net Dependable Capacity - Generally

- Net capability defined by NERC:
  - Net dependable capacity - maximum capacity a unit can sustain over an specified period, modified for seasonal limitations and reduced by the capacity required for station service or auxiliaries
  - Summer net capability of each unit may be used as winter net capability without further testing, at the option of the member

(See SPP, FERC Electric Tariff, Fifth Revised Volume No. 1, Original Sheet No. 941)
SPP Criteria 12.1.5.3 Rating Adjustments

g. Net capability established for wind plants determined on monthly basis, as follows:

i) Assemble up to the most recent ten years, with minimum of most recent five years, of hourly net power output (MW) data, measured at system interconnection point.

Values may be calculated from wind data, if measured MW values are not yet available. Wind data correlated with a reference tower beyond fifty miles is subject to Generation Working Group approval. For calculated values, at least one year must be based on site specific wind data.

ii) Select MW values occurring during top 10% of load hours for SPP region for each month (e.g., 72 hours for a typical 30 day month).

iii) Select MW value that can be expected from plant at least 85% of the time.

iv) Seasonal or annual net capability may be determined by selecting appropriate monthly MW values corresponding to host control area’s peak load month of the season of interest.

v) Net capability calculation shall be updated at least once every three years.

Waiver Request Discussion

• Attachment J, Section C.2.ii - Allows all or part of excess above Safe Harbor Cost Limit to be classified as Base Plan Upgrade Cost, taking into account extent to which commitment to new or changed DR exceeds five-year commitment.

- EDE reservation 1222640 is 20-year reservation.
- Aug. 2007 letter to SPP - EDE commits to Cloud County Wind farm.
- Analysis based on AG1-2007-AFS-6. Unknown if further studies required.
- SPP recommends increase of $50,625 from $1,800,000 Base Plan Funding.
  - Based on same calculation used for OGE / GSEC waivers and MW-MI calculation - indicating five zones benefiting from this commitment.
Waiver – Fuel Diversity

- EDE requested waiver to foster fuel diversity
- SPP will not recommend changing SPP policy to grant a waiver based on request to encourage fuel diversity
- FERC rejected language in SPP’s Attachment J that would have permitted a waiver to foster fuel diversity
- SPP must show how parties paying associated waiver costs would benefit from increased fuel diversity (Southwest Power Pool, Inc., 112 FERC ¶ 61,319 (2005), P. 19.)
- EPAct 2005 directs states to take up issue and consider value of fuel diversity (PURPA Section 111(d) (12) of Section 1251 of EPAct 2005)

Waiver – Fuel Diversity

- Most states in SPP region are addressing this issue - not all at the same stage of investigation:
  - Missouri, Case No. EO-2006-0494
  - Kansas, Docket No. 07-GIME-578-GIE
  - Arkansas, Docket No. 06-028-R
  - Texas, Project No. 33672
- Significant industry sentiment that integrated resource planning - including consideration of fuel diversity - is driven by specific issues within load-serving entity
- Fuel diversity is a policy decision for state regulators (RSC), stakeholders, and Board of Directors.
**SPP Conclusions and Recommendation – EDE Waiver Request**

- Current SPP Tariff - Net Dependable Capacity to be used for calculating Safe Harbor Cost Limit for all resources, including wind
- SPP cannot waive Tariff provisions
- SPP will not seek to establish fuel diversity policy
- Recommends a Waiver for the Commitment in Excess of Five Years
- Total Base Plan funding increase - $50,625
- Total Base Plan Funding with Waiver - $1,850,625

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AEP Waiver Request

November 2007
Waiver Request Summary

- AEP reservation 1162214 studied in SPP-2006-AG3-AFS-9
- AEP requesting 455 MW from Turk Power plant
- Base plan funding maximum calculated:
  \[ 455 \text{ MW} \times \$180,000/\text{MW} = \$81,900,000 \]
- Nov. 2, 2007 Letter - AEP requests waiver
- Submittal to SPP Board of Directors within 120 days per Tariff - required by March 1, 2008
- SPP Board of Directors meets Jan. 29, 2008

Benefit Analysis

- Capacity needed to meet anticipated Load Growth
- Fuel diversity for project participants
- SWEPCO CCN filings represent Turk Power Plant option as better of four options:
  - Two pulverized coal
  - Two IGCC (integrated gasification combined cycle)
Benefit Analysis

- Unit dispatchable
- Full load heat rate - 8992 BTU/kWh
- Not near a non-attainment area
- SWEPCO projects 87.6 % unit availability
- Life of plant commitment

Waiver Request Discussion

- **Attachment J, Section C.2.ii** - Allows all / part of excess above Safe Harbor limit to be classified as Base Plan funded, when new or changed DR exceeds five-year commitment
  
  - AEP reservation 1162214 is 20-year reservation
  - AEP committed to the life of Turk Plant - noted in Nov. 2007 letter to SPP
  - DR longevity consistent with SPP recommendation for approval of OGE, Westar, AECC, and OMPA waivers (approved by RSC and BOD)
CAWG Discussion of Turk Waivers

- March 2007 - proposed consideration of $180,000/MW Safe Harbor limit funds for all Turk participants
  - $111,240,000
- SPP-2006-AG3-AFS-9 required upgrades equal to $148,209,895
- Aggregate Study Base Plan funding analysis should not combine capacity in this manner:
  - Individual Project participants response factors may cause different upgrades
  - Not consistent with Attachment Z Section V: Cost Allocation for Requested Upgrades

SPP Recommendation for AEP Waiver

- Analysis should be complete since all customers agreed to remain after completion of Aggregate Facility Study
- Turk Generation Interconnection studies complete - Interconnection Agreement has been executed
- Recommend that Base Plan funding be increased to 100% of required E&C cost associated with addition of Turk plant DR for AEP
  - Based on longevity of reservation and commitment to Turk Plant presented
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Wind and Base Plan Funding

Larry Holloway
Kansas Corporation Commission

Issues

• Treatment of wind generation under the current tariff
• Why wind may be different
• Alternatives for consideration
III.B, Attachment J of the Tariff

Network Upgrades, with a cost that exceed $100,000, associated with new or changed Designated Resources shall be classified as Base Plan Upgrades if the Designated Resource or the associated upgrades (as applicable) meets each of the following conditions:

• 1. The Transmission Customer’s commitment to the Designated Resource has a duration of at least five years;

• 2. In the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer’s existing Designated Resources plus the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer’s projected system peak responsibility determined pursuant to SPP Criteria 2; and

• 3. The cost of Network Upgrades associated with the new or changed Designated Resource is less than or equal to $180,000/MW times the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity (the “Safe Harbor Cost Limit”).

III.B.2 of Attachment J is the Issue

(emphasis added)

• “In the first year the Designated Resource is planned to be used by the Transmission Customer, the accredited capacity of the Transmission Customer’s existing Designated Resources plus the lesser of: (a) the planned maximum net dependable capacity applicable to the Transmission Customer or (b) the requested capacity; shall not exceed 125% of the Transmission Customer’s projected system peak responsibility determined pursuant to SPP Criteria 2;
Where did this Provision come from?  
(as I recall it)

- During the development and negotiations for the initial Cost Allocation Plan (CAP) the following items were considered for Base Plan Funding (BPF):
  - Cost allocation of reliability upgrades to the constructing zone
  - Regional cost allocation of high voltage upgrades
  - Using some type of economic model to allocate the costs of all reliability upgrades
  - Regional cost allocation of all upgrades
  - Etc.

Why the Compromise CAP?

- Concerns with various proposals
  - Either a total zonal or a total regional allocation was perceived to have free riders
    - Also did not provide any incentive to locate generation with any consideration to costs of transmission upgrades
    - Did not recognize the need for Load Serving Entities (LSEs) to jointly own or purchase generation
  - Some cost allocation schemes could cause members to leave SPP
    - Far less consensus and commitment on the part of members at that time
  - A more socialized cost allocation scheme was perceived as creating problems for state commission approval.
Is Access to new or changed DNRs an Economic or a Reliability Concern?

- Many argued at the time that access to new or changed DNRs was actually an economic concern, since generation decisions relied on the purchasers economic evaluation
  - However, it was decided that making sure all firm generation capacity could be used on a firm basis by network customers in SPP was a reliability concern
  - The rational is that it does nothing to satisfy reliability criteria for the overload, etc., if LSE’s cannot access their required capacity margin
  - The 125% of peak load requirement represents a 20% capacity margin
    - \[ G = 125\% \text{ L and } CM = \frac{(G - L)}{G}, \text{ then} \]
    - \[ CM = \frac{(1.25L - L)}{1.25L} = \frac{0.25L}{1.25L} = 20\% \]
  - This is not that large of a margin, when the minimum is 12%!!
  - This represents accredited capacity because it is based on the capacity margin.

III.A.2 Appendix J, the CAP for BPF Upgrades

- If the cost of a Base Plan Upgrade is greater than $100,000, then:
  - i. \( X\% \) of the annual transmission revenue requirement associated with such Base Plan Upgrade shall be allocated to the Base Plan Region-wide Annual Transmission Revenue Requirement and recovered through the Base Plan Region-wide Charge. The initial value of \( X \) shall be 33%.
  - ii. \( (100-X)\% \) of the annual transmission revenue requirement associated with such Base Plan Upgrade shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement and recovered through the Base Plan Zonal Charge. This portion of the annual transmission revenue requirement for each Base Plan Upgrade shall be allocated to the Base Plan Zonal Annual Transmission Revenue Requirement of specific Zones based on the Zones’ share of the incremental positive MW-mile benefits as computed in Section 4 of Attachment S to this Tariff. Each Zone with a benefit of at least 10 MW-miles from a given Base Plan Upgrade shall be allocated a portion of the Base Plan Zonal Annual Transmission Revenue Requirement for such upgrade based on its incremental positive MW-mile benefit divided by the sum of the incremental positive MW-mile benefits for all of those Zones with a benefit of at least 10 MW-miles from the upgrade, provided that such allocation represents an engineering and construction cost of at least $100,000. Qualified BPF costs are allocated under
    - Basically 1/3 regionally and 2/3 zonally based upon zonal benefits perceived as incremental MW-miles of transmission capacity.
Why wind may be different

• The productivity of wind generation is based upon the location of the resource.
• Wind generation requires intensive land usage
  – A 1,000 MW wind farm would cover around 70 square miles – a magnitude of 10 times more than needed for a large coal or nuclear site
  – High productivity wind farms need unobstructed wind
    • The result is these are going to be commonly located at distances very remote to the load
    • These areas in SPP are in regions that currently have little transmission access.
• And, of course, the accredited capacity for wind is generally around 10% of nameplate
  – But to use and justify wind generation the load must have access to the production whenever it is available
• But necessary transmission upgrades for wind generation may be focused on the production zones
  – The zonal net positive MW-mile allocator has the potential to over-allocate the costs to the zones where transmission customers see little benefit.

Why wind is different (cont)

• We could encourage wind by changing the qualification criteria of Appendix J III.B.2
  – This does not mean that the current language allows anything but accredited capacity, clearly that never was the intent.
    • This does mean that wind would be treated differently.
• This also does nothing to address the concerns with the zonal allocation, which must be addressed before wind can be treated differently.
Example of the Basic System

LSE A Purchases Energy from Wind Farm 1

Transmission upgrade
Example 2

Zone 4 Load Purchases Energy from Wind Farm 2

Transmission upgrade

Example 3

Zone 3 Load Purchases Energy from Wind Farm 3

Transmission upgrade
Concerns – why wind is different

- Example 1 – Most of the zonal allocation goes to zone 1
- Example 2 – Most of the zonal allocation goes to zone 2
- Example 3 – Zonal allocation to all zones
- Example 4 – Zonal allocation to zone 1
- Result
  - Zone 1 and 2 rates go up substantially to benefit wind purchase by LSEs and Loads in Zone 3 and 4
- Big picture
  - This may be an unsustainable outcome
  - This does not support some sort of regional resource planning (that is supposed to be one of the focuses of the RSC)
  - Right now it looks like wind in the western part of SPP and baseload in the eastern part (2 new large coal units in Arkansas)
  - Few believe wind can reliably provide more than 25% of a utilities energy needs
    - But this requires about 30% nameplate of utility’s peak load and would almost all be installed in the Western Part of SPP – the result could be over 12,000 MW of wind just for SPP load – most of it installed in the western half of SPP.
SPP – potential internal wind requirements

• SPP 2006 results from SPP 2007 EIA-411
  – 42,882 MW peak load
  – 201521 GWH energy
• Results in about a 54% load factor
• How does this translate into amount of wind needed at different RPS levels?
  – Just for SPP alone – without exports.

<table>
<thead>
<tr>
<th>RPS Requirement</th>
<th>Amount of Wind Generation at 40% Capacity Factor</th>
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<tbody>
<tr>
<td>1.00%</td>
<td>0</td>
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<tr>
<td>5.00%</td>
<td>2000</td>
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<td>10000</td>
</tr>
<tr>
<td>30.00%</td>
<td>12000</td>
</tr>
</tbody>
</table>
Proposed Solution

- Requests for Wind still uses the same cost allocation for the accredited capacity.
- If request does not exceed 125% peak load (using accredited capacity) that the accredited capacity from the wind project is allowed $180K/MW of BPF.
  - Assuming 10% of nameplate this is $18K/MW of nameplate.
- But, the remaining amount is allowed (within certain parameters) and allocated entirely regionally.
  - (Nameplate – accredited) at $180K/MW regionally allocated.
  - Only applies to amount not funded by current BPF.
- Amount of wind that would qualify would be limited to 30% nameplate of the peak load.

Example A

- NITS customer has a 1000 MW peak load and 1200 existing DNRs.
  - Proposes to purchase 200 MW of wind generation accredited at 20 MW.
  - Full delivery requires $25 M transmission upgrades.
  - 1200 + 20 = 1220 > 122% of peak load > qualifies.
  - 20 MW ($180k/MW) = $3.6 M BPF.
    - $1.2 M regional allocation, $2.4 M zonal allocation.
  - Remaining (200 – 20) = 180MW ($180K/MW) = $32.4 million.
    - Qualified funding = $3.6 M + $32.4 M = $ 36 M.
    - $36M > $25M, so.
    - $3.6M under current BPF, $25M - $3.6M = $21.4M regionally.
  - Result is $2.4M allocated zonally, $22.6M ($21.4M + $1.2M) allocated regionally.
Example B

- NITS customer has a 1000 MW peak load and 1200 existing DNRs
  - Proposes to purchase 200 MW of wind generation accredited at 20 MW
  - Full delivery requires $40 M transmission upgrades
  - $1200 + 20 = 1220 > 122% of peak load > qualifies
  - 20 MW ($180k/MW) = $3.6 M BPF
    - $1.2 M regional allocation, $2.4 M zonal allocation
  - Remaining (200 – 20) = 180MW ($180K/MW) = $32.4 million
    - Qualified funding = $3.6 M + $32.4 M = $ 36 M
    - $36M < $40M, so
    - $3.6M under current BPF, $32.4 wind regional allocation
  - Result is $2.4M allocated zonally, $33.6M ($32.4M + $1.2M) allocated regionally
  - Remainder – ($40M - $36M) $4M allocated to the customer

Example C

- NITS customer has a 1000 MW peak load and 1240 existing DNRs
  - Proposes to purchase 200 MW of wind generation accredited at 20 MW
  - Full delivery requires $25 M transmission upgrades
  - $1240 + 20 = 1260 > 126% of peak load > only 10 MW (or half) qualifies
  - 10 MW ($180k/MW) = $1.8 M BPF
    - $0.6 M regional allocation, $1.2 M zonal allocation
  - Remaining (100 – 10) = 180MW ($180K/MW) = $16.2 million
    - Qualified funding = $1.8 M + $16.2 M = $ 18 M
    - $18M < $25M, so
    - $1.8M under current BPF, $16.2 wind regional allocation
  - Result is $1.2M allocated zonally, $16.8M ($16.2M + $0.6M) allocated regionally
  - Remainder – ($25M - $18M) $6M allocated to the Customer
Example D

- NITS customer has a 1000 MW peak load and 1200 existing DNRs
  - Proposes to purchase 400 MW of wind generation accredited at 20 MW
  - Full delivery requires $60 M transmission upgrades
  - $1200 + 40 = 1240 = 124% of peak load > 40 MW 10 MW ($180k/MW) = $7.2 M BPF
    - $2.4 M regional allocation, $4.8 M zonal allocation
  - But 400 MW of wind is 40% of peak load so only 300 MW (30% of 1000 MW qualifies for remainder
  - Remaining (300 – 40) = 260MW ($180K/MW) = $46.8 million
    - Qualified funding = $7.2 M + $46.8 M = $ 54 M
    - $54M < $60M, so
    - $7.2M under current BPF, $46.8 wind regional allocation
  - Result is $4.8M allocated zonally, $49.2M ($46.8M + $2.4M) allocated regionally
  - Remaining (260 – 40) = 220MW ($180K/MW) = $39.6 million
    - Total allocation is $7.2M + $54M + $49.2M = $100.6M
    - Remainder – ($60M - $100.6M) $40.6M allocated to the Customer

Conclusions

- There may well be other methods or limits we can consider
  - Nonetheless we need to consider the fact that the wind will be developed primarily in only a portion of SPP
    - Many utilities will want access to the wind
  - This method does acknowledge the difference between wind and other generation resources
    - Fits into fuel diversity and other concerns RSC added to tariff language
  - Allowing nameplate wind capacity instead of accredited capacity under III.B.2 of Appendix J is treating wind differently and is a consequence not intended or envisioned when the current cost allocation plan was developed – alternate methods for wind related transmission upgrade cost allocation would establish a cost allocation scheme that is not an unintended consequence but is instead a deliberate approach
Overview

• Purpose
  • Solicit feedback from a broad range of stakeholders on key issue related to transmission planning
  • Asked for responses in two time frames
    1. Short Term – between now and 2010
    2. Long-term – by 2020
  • Use results to shape key input assumptions
  • Main Topic Areas
    • Supply & Demand
    • Fuel & Environmental Constraints
  • Distribution
    • SPP Members
    • Regulators
    • Other related organizations

Supply Side Related Responses

Renewable Portfolio Standards

• Most believed that some form of federal or state-mandated RPS would be in place in by 2020
  1. 76% thought some form of state mandate would be in place by 2020

• Amount
  • <10% in short term
  • Between 10% and 15% in long term
Treatment of Wind Resources

Majority recognize increase in wind resources from today’s 3%
- 68% say it could be as high as 10% in short term
- 72% see potentially 15% in long-term

Transmission needs to support new wind generation
- 67% believe study should model transmission expansion to support export of wind generation
- 74% see increase in net exports in long-term

Nuclear Generation

- Short term outlook - overwhelming majority see no change in short term
- Long-term outlook – 77% see at least some incremental capacity being added
**Demand Side Responses**

- Scope of questions included utility demand programs, price responsive load, and energy efficiency
- Summary across all three areas
  - Short term outlook – overwhelming majority (80.4%) see current levels of demand response capability (3%-6%) being roughly maintained
  - Long-term outlook
    - Increase in utility demand response programs could be in the 7%-10% of load
    - Price sensitive load remains in same range of 3%-6%

**Fuel & Environmental Constraints**

- **Emissions Constraint Policies**
  - 81% see cap and trade system being put in place
  - Majority see price of emissions credits increasing at (31%) or greater (58%) than rate of inflation
- **Fuel Prices**
  - **Natural Gas prices**
    - upward pressure on prices at or greater than rate of inflation
  - 78% see prices rising greater than inflation in long-term forecast
  - **Coal prices**
    - Prices increase at a pace slower than rate of change in natural gas prices
Interpreting the Results

- **Supply & Demand Areas**
  - An RPS standard will be in place in the long term that could be as high as 10% or more
  - Wind resources
    1. Could make up as much as 10%-15% of the region’s capacity
    2. Transmission to support exports of these resources to the Eastern Interconnection should be evaluated
  - Nuclear Generation in the future will remain constant in the short term with the potential for incremental capacity in the long term
  - Demand side resources
    1. Will continue to be in the 3-6% range in the short term
    2. Utilities will increase the amount of demand side programs to as much as 10% in the long-term
  - Imports/Exports
    - SPP will continue its current pattern although an increase in export capability should be evaluated

- **Fuel & Environment**
  - Emissions constraints
    1. A cap and trade system will be in place
    2. The value of emissions credits is expected to increase at a rate at or above inflation
  - Fuel Price Forecasts
    - Natural gas prices will increase at or above the rate of inflation
    - Coal prices will increase at a rate below that of natural gas prices

Questions?