Benefit/Cost Ratio Primer 101

for the

Regional Allocation Review Task Force

August 4, 2011

SPP PLANNING AND COST ALLOCATION OVERVIEW
Transmission = 10% Retail Electricity Rates

Transmission enables optimal use of our region’s diverse generating resources, including coal, natural gas, hydroelectric, nuclear, and wind energy.

How does SPP decide what and where transmission is needed?

- Generation Interconnection Studies
  - Determines transmission upgrades needed to connect new generation to electric grid

- Aggregate Transmission Service Studies
  - Determines transmission upgrades needed to transmit energy from new generation to load
  - Shares costs of studies and new transmission

- Specific transmission studies
- Integrated Transmission Planning process
Why do we need more transmission?

- In the past, built least-cost transmission to meet local needs
- Today, proactively building “superhighways” to benefit region

Finding Balance

Minimum for Reliable Delivery to Customers
More Transmission Needed
Expand Transmission
Customer Energy Cost

Less to Low-Cost Delivery

More

Less

Amount of Transmission
What is congestion?

- Congestion or “bottlenecks” happen when you can’t get energy to customers along a certain path
  - Desired electricity flows exceed physical capability
- Congestion caused by:
  - Lack of transmission, often due to load growth
  - Line and generator maintenance outages
  - Unplanned outages such as storms or trees on lines
  - Too much generation pushed to grid in a particular location
  - Preferred energy source located far from customers
- Results in inability to use least-cost electricity to meet demand

Congestion prevents access to lower-cost generation
Congestion’s Impact on Wholesale Market Prices
January 26, 2010 Interval Ending 12:15 PM

LAKALAIATSTR: Lake Road – Alabama 161kV (MPS) Fio Latan – Stranger Creek 345kV (KCPL)

What is Integrated Transmission Planning?

• **Goal:** Design transmission backbone to connect load to the most reasonable generation alternatives
  – Strengthen ties to Eastern and Western Interconnections
  – Improve connections between SPP’s east and west regions

• **Horizons:** 20, 10, and 4 year – 40 years

• **Focus:** Regional, integrated with local

• **Resulting in:** Comprehensive list of needed projects for SPP region over next 20 years
  – With 40 year financial/economic analysis

• **Underlying Value:** Reliability and Economics are inseparable
Integrated Transmission Planning

- Increasing Refinement
- Reducing Uncertainty
- Narrowing Focus

Integrated Transmission Planning Process

- Reliability Analysis
  - Annual Near-Term plan
  - Identifies potential problems and needed upgrades
  - Coordinates with ITP10, ITP20, Aggregate and Generation Interconnection study processes

- Economics and Reliability Analysis
  - Analyzes transmission system for 10-year horizon
  - Establishes timing of ITP20 projects
  - Develops 345 kV+ backbone for 20-year horizon
  - Studies broad range of possible futures
Transmission planners consider:

- What parts of grid need strengthening to “keep the lights on”?
  - Redundancies necessary to account for a line being out
- Where is current and future generation located?
- Where are electricity consumers located?
- Where on the grid do we frequently see congestion (more traffic than roads can accommodate)?
- Will laws mandating more renewable energy or a carbon tax impact traffic?
- How do coal/gas prices impact traffic?
  - People will use more coal if gas prices rise, and vice versa
- How do regional temperatures impact traffic?
  - If temperature differs across region, one area may need more energy

Generation = 60% Retail Electricity Rates

Without transmission, we can’t deliver this capital-intensive generation to where it’s needed across region
Who pays for these transmission projects?

- **Sponsored:** Project owner builds and receives credit for use of transmission lines
- **Directly-assigned:** Project owner builds and recovers cost through retail rates
- **Highway/Byway:** Most SPP projects paid for under this methodology

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Region Pays</th>
<th>Local Zone Pays</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 kV and above</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>above 100 kV and below 300 kV</td>
<td>33%</td>
<td>67%</td>
</tr>
<tr>
<td>100 kV and below</td>
<td>0%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Projects Constructed 2005-2010

[Map showing projects constructed from 2005 to 2010]
Projects with Notifications to Construct

Balanced Portfolio
Priority Projects

2010 Plan for 2030

2010 ITP20 Plan
Approved by SPP Board of Directors
January 2011

[Map with project locations indicated]
POWER WORLD DEMONSTRATION

BENEFIT ANALYSIS BACKGROUND
Background: Cost Allocation - H/B 101

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Regional</th>
<th>Zonal</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 kV and Above</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>100 kV - 299 kV</td>
<td>33%</td>
<td>67%</td>
</tr>
<tr>
<td>Below 100 kV</td>
<td>0%</td>
<td>100%</td>
</tr>
</tbody>
</table>

Background: Adjusted Production Cost

• Adjusted Production Costs (APC):
  – Industry accepted metric tied to generation costs
  – Based on a Day Ahead Market: Locational Marginal Price (LMPs)
  – Measures benefit on an hourly basis, over a year’s simulation
  – Adjusted means that the simulation takes into account the purchase and sale of economic energy
  – Price nodes are aggregated by zone
Background: APC Formulation

APC = Production Cost – Revenue from Sales + Cost of Purchases

Where

Revenue from Sales = MW Export x Zonal LMP_{gen weighted}

And

Cost of Purchases = MW Import x Zonal LMP_{load weighted}

Background: Input Assumptions

- Fuel Price Forecasts
  - Coal, Gas, Oil, Uranium
- Generating Unit Parameters
  - Operating Characteristics
  - Ramp Rates
  - Availability: Forced Outages, Maintenance Schedules
  - Wind Profiles
- Load Forecasts: Peak Demand, Energy Profiles
- Hurdle Rates Between Utilities & Regions
- Transmission Topology
Background: Benefits, Outputs

- APC captures the effects of:
  - Fuel Prices
  - Run Times
  - Congestion
  - Ramp Rates
  - Energy Purchases
  - Energy Sales
  - Emission Costs (Environmental)

Background: Benefits, Benchmarking

- Benchmarking uses planning data to compare to historical operations
- This is an important step to build confidence in model results
- It's important to note: since historical data is an imbalance market, and planning is on a day ahead market, results should not match exactly
- Instead, benchmarking represents a “sanity test” to validate a model
Generation by Unit Category in SPP

Coal and combined cycle gas generation sources provide 79% of the total generation in the simulation. Historically, according to the EIA, these sources provided 77%. The gas prices between 2010 and the simulation warrant this difference.

Hydro Generation by Month

2009 and 2010 SPP Hydro
2011 TP T10 SPP Hydro
Operating & Spinning Reserve

- Graph of capacity outaged by time period
- Correlates with GADS data

Generator Maintenance Outages
Transmission Line & Transformer Outages

- PROMOD® simulations do not take transmission maintenance into account
- This is an everyday operational concern
- Take Away: Results from PROMOD may demonstrate lower benefit than may be actual

Average LMP by Area

- The average LMP of each area trends well with the results of the EIS market in 2008, 2009, and 2010
Expected Demand @ Peak
Aug 3rd, 5pm 2022
Current Goals & Standards

Wind Energy
37 TWh for Future 1
52 TWh for Future 2

Other Renewable Energy
2 TWh for both futures

Approximate RES %
14% in Future 1
20% in Future 2

Number of Flowgates
Binding
48 flowgates

Avg. Shadow Price
4.19 $/MWh

Hours with Congestion
7,563

Highest Prices in Hours
July 13th 1500
July 13th 1600
July 13th 1700
Benefits/Cost (B/C) Ratio Computation

• Benefits are determined on a zone by zone basis for a year
• This benefit is compared to the allocated costs by each zone
• This gives a B/C ratio
• A B/C ratio of 1.0 means that a project just pays for itself
Intro: Hypothetical RTO (H-RTO)

- RTO B/C 101 at the request of the RARTF is designed to provide background for RARTF to better understand B/C Ratios
- RTO B/C 101 uses a Hypothetical RTO (H-RTO)
- H-RTO has Five Zones, “A” thru “E”
- H-RTO has 2 sets of transmission upgrades:
  - Portfolio I (2011-13 @ $107.5M)
  - Portfolio 2 (2014-16 @ $92.5M)

H-RTO Considerations

Cost Allocation Methodology:
- H-RTO has the same Cost Allocation Method as SPP (Highway/Byway)
- H-RTO load share ration for each zone is computed the same as SPP – CP 12

Benefit Approach:
- H-RTO uses 2 approaches to calculating B/C Ratios
  - Adjusted Production Cost (APC) B/C
  - Societal B/C
H-RTO: CHARACTERISTICS AND FACTS

H-RTO Foot Print

Zone A
Zone B
Zone C
Zone D
Zone E
H-RTO Foot Print - Overview

- Zone A and Zone B in the west are high renewable zones with low cost power
- These zones wish to move renewable energy to the east

H-RTO Foot Print - Overview

- Zones B, D & E are higher cost zones with a desire to import renewable energy
H-RTO Foot Print - Overview

- Congestion exists between the western and the eastern zones
- This congestion limits the import of desired energy

Hypothetical RTO – Load Ratio Share (12CP)

Load Ratio Share

- A, 41.7%
- B, 25.0%
- C, 16.7%
- D, 13.3%
- E, 3.3%
**Hypothetical RTO – Characteristics by Zone**

<table>
<thead>
<tr>
<th>Zone</th>
<th>Average 12 CP Load, previous year's actuals (MW)</th>
<th>Load Ratio Share (%)</th>
<th>Net Plant Carrying Charge (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>2500</td>
<td>41.67%</td>
<td>16.50%</td>
</tr>
<tr>
<td>B</td>
<td>1500</td>
<td>25.00%</td>
<td>15.00%</td>
</tr>
<tr>
<td>C</td>
<td>1000</td>
<td>16.67%</td>
<td>18.00%</td>
</tr>
<tr>
<td>D</td>
<td>800</td>
<td>13.33%</td>
<td>13.00%</td>
</tr>
<tr>
<td>E</td>
<td>200</td>
<td>3.33%</td>
<td>17.00%</td>
</tr>
<tr>
<td>Totals and Weighted Average NPCC</td>
<td>6000</td>
<td>100.00%</td>
<td>15.66%</td>
</tr>
</tbody>
</table>
H-RTO Portfolio 1 Projects

H-RTO: Portfolio I (2011-2013)

<table>
<thead>
<tr>
<th>UID</th>
<th>Description</th>
<th>Zone</th>
<th>In Service Year</th>
<th>Total Investment</th>
<th>Zonal NPCC</th>
<th>Total ATRR</th>
<th>Regional ATRR</th>
<th>Zonal ATRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>Line from Substation in Zone A to Border of Zone B</td>
<td>A</td>
<td>2013</td>
<td>$100,000,000</td>
<td>16.5%</td>
<td>$105,000,000</td>
<td>$16,500,000</td>
<td>$0</td>
</tr>
<tr>
<td>A2</td>
<td>Transformer installation on border of Zone A and Zone B (Active support of A1 and B1)</td>
<td>A</td>
<td>2013</td>
<td>$5,000,000</td>
<td>16.5%</td>
<td>$5,250,000</td>
<td>$825,000</td>
<td>$0</td>
</tr>
<tr>
<td></td>
<td>Tolerating high voltage distribution supported by EPP E1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Totals</strong></td>
<td></td>
<td></td>
<td><strong>$105,000,000</strong></td>
<td><strong>16.5%</strong></td>
<td><strong>$17,250,000</strong></td>
<td><strong>$17,250,000</strong></td>
<td><strong>$0</strong></td>
</tr>
</tbody>
</table>
### Portfolio 1: First Year Cost Allocated by Zones

<table>
<thead>
<tr>
<th>ID</th>
<th>Description</th>
<th>Zone</th>
<th>In Service Year</th>
<th>Total Investment</th>
<th>Zone A</th>
<th>Zone B</th>
<th>Zone C</th>
<th>Zone D</th>
<th>Zone E</th>
<th>Check: Assigned - Allocated</th>
</tr>
</thead>
<tbody>
<tr>
<td>E1</td>
<td>Transform Zone 1 cost to support local facilities; new voltage side battery cost allocation</td>
<td>E</td>
<td>2012</td>
<td>$2,800,000</td>
<td>$116,648</td>
<td>$71,698</td>
<td>$47,493</td>
<td>$37,607</td>
<td>$108,742</td>
<td>$425,800</td>
</tr>
<tr>
<td>A1</td>
<td>Large new transmission to Zone A to balance Zone D</td>
<td>A</td>
<td>2013</td>
<td>$100,000,000</td>
<td>$6,876,000</td>
<td>$4,125,000</td>
<td>$2,750,000</td>
<td>$2,200,000</td>
<td>$500,000</td>
<td>$10,000,000</td>
</tr>
<tr>
<td>A2</td>
<td>Transformation of Substation on Border of Zone A and Zone B used to support demand in A. Batteries achieving high voltage side battery cost allocation</td>
<td>A</td>
<td>2013</td>
<td>$5,000,000</td>
<td>$345,750</td>
<td>$206,250</td>
<td>$117,000</td>
<td>$110,000</td>
<td>$255,000</td>
<td>$525,000</td>
</tr>
<tr>
<td></td>
<td>Totals</td>
<td></td>
<td></td>
<td>$107,000,000</td>
<td>$7,357,796</td>
<td>$6,462,298</td>
<td>$3,254,948</td>
<td>$2,747,047</td>
<td>$727,042</td>
<td>$17,750,000</td>
</tr>
</tbody>
</table>

### Portfolio 1: C/A by Zone to 2051

The chart illustrates the ATRR forecast by year with 3% depreciation for Portfolio 1 from 2021 to 2051. Each zone is represented separately, and the total is shown at the end. The chart shows a decline in ATRR over the years for each zone, with Zone E showing the highest ATRR values and Zone A showing the lowest. The chart visually represents the financial trends and projections over the specified period.
Portfolio 1: APC Benefits Zones (2013)

<table>
<thead>
<tr>
<th>Zone</th>
<th>Costs (2013)</th>
<th>APC (2013)</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone A</td>
<td>$7,337,396</td>
<td>$9,000,000</td>
<td>1.2</td>
</tr>
<tr>
<td>Zone B</td>
<td>$4,402,438</td>
<td>$6,000,000</td>
<td>1.4</td>
</tr>
<tr>
<td>Zone C</td>
<td>$2,934,958</td>
<td>$2,900,000</td>
<td>1.0</td>
</tr>
<tr>
<td>Zone D</td>
<td>$2,347,967</td>
<td>$1,700,000</td>
<td>0.7</td>
</tr>
<tr>
<td>Zone E</td>
<td>$527,242</td>
<td>$50,000</td>
<td>0.1</td>
</tr>
</tbody>
</table>

Total: $17,750,000 / $19,650,000 (B/C = 1.11)

Portfolio 1: APC + Societal Benefit (2013)

<table>
<thead>
<tr>
<th>Zone</th>
<th>Est. Benefit (2013)</th>
<th>APC + Societal Benefit</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone A</td>
<td>$8,000,000</td>
<td>$17,000,000</td>
<td>2.3</td>
</tr>
<tr>
<td>Zone B</td>
<td>$4,000,000</td>
<td>$10,000,000</td>
<td>2.3</td>
</tr>
<tr>
<td>Zone C</td>
<td>$1,000,000</td>
<td>$3,900,000</td>
<td>3.9</td>
</tr>
<tr>
<td>Zone D</td>
<td>$3,500,000</td>
<td>$5,200,000</td>
<td>1.5</td>
</tr>
<tr>
<td>Zone E</td>
<td>$600,000</td>
<td>$850,000</td>
<td>1.4</td>
</tr>
</tbody>
</table>

Total: $17,100,000 / $36,750,000 (B/C = 2.1)
Portfolio 1: Benefits to 2051

P1: APC Benefit Over Time

Portfolio 1: 40 Year Benefits vs Costs

P1: 40 Year Benefit vs Costs (APC Only)
H-RTO PORTFOLIO 2 PROJECTS: 2014-16

H-RTO Portfolio 2 Projects
### HRTO: Portfolio 2 (2014-2016)

#### Portfolio 2 Upgrades: 2014 thru 2016

<table>
<thead>
<tr>
<th>Upgrade ID</th>
<th>Description</th>
<th>Zone</th>
<th>In Service Year</th>
<th>Total Investment</th>
<th>Zone MPCC</th>
<th>Total ATRR</th>
<th>Regional ATRR</th>
<th>Zonal ATRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td>Lines from Substation on Beacon of Zone A to Zone B</td>
<td>B</td>
<td>2014</td>
<td>$42,000,000</td>
<td>15.00%</td>
<td>$4,400,000</td>
<td>$9,400,000</td>
<td>$0</td>
</tr>
<tr>
<td>D1</td>
<td>D1 Lines from Zone D</td>
<td>D</td>
<td>2015</td>
<td>$26,000,000</td>
<td>13.00%</td>
<td>$2,600,000</td>
<td>$2,600,000</td>
<td>$0</td>
</tr>
<tr>
<td>B2</td>
<td>Line in support of Load Growth in Zone B</td>
<td>B</td>
<td>2016</td>
<td>$6,500,000</td>
<td>15.00%</td>
<td>$975,000</td>
<td>$321,750</td>
<td>$653,250</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td></td>
<td></td>
<td></td>
<td>$85,500,000</td>
<td>14.85%</td>
<td>$15,225,000</td>
<td>$12,277,750</td>
<td>$653,250</td>
</tr>
</tbody>
</table>

### Portfolio 2: Cost Allocated by Zones

#### Portfolio 2 Upgrades: 2014 thru 2016

<table>
<thead>
<tr>
<th>Upgrade ID</th>
<th>Description</th>
<th>Zone</th>
<th>In Service Year</th>
<th>Total Investment</th>
<th>Zone A</th>
<th>Zone B</th>
<th>Zone C</th>
<th>Zone D</th>
<th>Zone E</th>
<th>Check That Total Assign = Total ATRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td>Lines from Substation on Beacon of Zone A to Zone B</td>
<td>B</td>
<td>2014</td>
<td>$31,600,000</td>
<td>$3,900,000</td>
<td>$2,382,500</td>
<td>$1,773,000</td>
<td>$1,810,000</td>
<td>$15,800</td>
<td>$11,400,000</td>
</tr>
<tr>
<td>D1</td>
<td>D1 Lines from Zone D</td>
<td>D</td>
<td>2015</td>
<td>$30,000,000</td>
<td>$1,903,333</td>
<td>$8,613,001</td>
<td>$433,333</td>
<td>$346,667</td>
<td>$95,750</td>
<td>$2,500,000</td>
</tr>
<tr>
<td>C1</td>
<td>Line in Zone C to support load in Zone B</td>
<td>C</td>
<td>2016</td>
<td>$3,800,000</td>
<td>$0</td>
<td>$0</td>
<td>$548,000</td>
<td>$0</td>
<td>$548,000</td>
<td>$548,000</td>
</tr>
<tr>
<td>B2</td>
<td>Line in support of Load Growth in Zone B</td>
<td>B</td>
<td>2016</td>
<td>$6,500,000</td>
<td>$1,564,963</td>
<td>$731,688</td>
<td>$53,625</td>
<td>$42,666</td>
<td>$107,750</td>
<td>$321,750</td>
</tr>
<tr>
<td><strong>Totals</strong></td>
<td></td>
<td></td>
<td></td>
<td>$12,500,000</td>
<td>$5,154,968</td>
<td>$3,746,168</td>
<td>$2,893,950</td>
<td>$1,849,867</td>
<td>$412,202</td>
<td>$13,563,684</td>
</tr>
</tbody>
</table>

|                           |                                                       |      |                 | $15,565,000    | $0      | $0     | $0     | $0     | $0     | GOOD CHECK                         |
Portfolio 2: C/A by Zone to 2051

ALL PORTFOLIO PROJECTS: 2011-16
PORTFOLIO 1 & 2 COMBINED
All Portfolio Projects

H-RTO: All Portfolios (2011-2016)

<table>
<thead>
<tr>
<th>PLANNING SUMMARY, ALL TYPES</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>No of Upgrades</strong></td>
</tr>
<tr>
<td>7</td>
</tr>
</tbody>
</table>
### All Projects: By Zone (H/B)

#### Total Investment by Zone ($/YR)

<table>
<thead>
<tr>
<th>Zone A</th>
<th>Zone B</th>
<th>Zone C</th>
<th>Zone D</th>
<th>Zone E</th>
<th>Total Investment</th>
</tr>
</thead>
<tbody>
<tr>
<td>$105,000,000</td>
<td>$69,500,000</td>
<td>$3,000,000</td>
<td>$20,000,000</td>
<td>$2,500,000</td>
<td>$200,000,000</td>
</tr>
</tbody>
</table>

### All Projects: Cost Allocation by Zones

#### Total ATRR Assignment ($/YR)

<table>
<thead>
<tr>
<th>Zone A</th>
<th>Zone B</th>
<th>Zone C</th>
<th>Zone D</th>
<th>Zone E</th>
<th>Total ATRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>$12,492,292</td>
<td>$8,148,625</td>
<td>$5,536,917</td>
<td>$3,997,533</td>
<td>$1,139,633</td>
<td>$31,315,000</td>
</tr>
</tbody>
</table>
All Portfolio: C/A by Zone to 2051

Portfolio 1 & 2: APC Benefits Zones (2016)*

<table>
<thead>
<tr>
<th>Zone</th>
<th>Costs</th>
<th>APC</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone A</td>
<td>$12,492,292</td>
<td>$17,000,000</td>
<td>1.4</td>
</tr>
<tr>
<td>Zone B</td>
<td>$8,484,825</td>
<td>$12,000,000</td>
<td>1.5</td>
</tr>
<tr>
<td>Zone C</td>
<td>$4,996,917</td>
<td>$3,000,000</td>
<td>0.6</td>
</tr>
<tr>
<td>Zone D</td>
<td>$3,997,533</td>
<td>$4,100,000</td>
<td>1.0</td>
</tr>
<tr>
<td>Zone E</td>
<td>$1,339,833</td>
<td>$400,000</td>
<td>0.1</td>
</tr>
</tbody>
</table>

*Note: Portfolio 2 is incremental to Portfolio 1, i.e. both Portfolios together account for the benefit shown.
Portfolio 1 & 2: APC + Societal Benefits (2016) *

<table>
<thead>
<tr>
<th>Zone</th>
<th>Est. Benefit</th>
<th>APC + Societal Benefit</th>
<th>B/C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone A</td>
<td>$12,000,000</td>
<td>$29,000,000</td>
<td>2.3</td>
</tr>
<tr>
<td>Zone B</td>
<td>$7,000,000</td>
<td>$19,000,000</td>
<td>2.7</td>
</tr>
<tr>
<td>Zone C</td>
<td>$3,000,000</td>
<td>$6,000,000</td>
<td>2.0</td>
</tr>
<tr>
<td>Zone D</td>
<td>$4,200,000</td>
<td>$8,300,000</td>
<td>2.0</td>
</tr>
<tr>
<td>Zone E</td>
<td>$700,000</td>
<td>$800,000</td>
<td>0.7</td>
</tr>
</tbody>
</table>

*Note: Portfolio 2 is incremental to Portfolio 1, i.e. both Portfolios together account for the benefit shown.

Portfolio 1 & 2: Total Benefit to 2051

P1&2: APC Benefit Over Time

[Graph showing APC Benefit Over Time for various zones (A to E) with years ranging from 2017 to 2050, with benefit values increasing over time.]
Portfolio 1 & 2: 40 Year Benefits vs Costs

P1 & 2: 40 Year Benefit vs Costs (APC Only)

Who is “losing”? 

<table>
<thead>
<tr>
<th>Zone</th>
<th>APC</th>
<th>+ Societal</th>
<th>APC</th>
<th>+ Societal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone E</td>
<td>0.99</td>
<td>1.23</td>
<td>0.99</td>
<td>1.23</td>
</tr>
<tr>
<td>Zone C</td>
<td>0.99</td>
<td>1.80</td>
<td>0.80</td>
<td>1.20</td>
</tr>
<tr>
<td>Zone D</td>
<td>0.72</td>
<td>2.21</td>
<td>1.03</td>
<td>2.06</td>
</tr>
</tbody>
</table>

- Zone E is still a “loser” after even societal benefits are added to the equation
- Zone C and D are “losers” at points in time
- Zones A and B are always “winners”
What about remedies??

• Possible Remedies:
  – Revenue Transfers
  – Advance Projects/Staging Timing
  – New Projects (Portfolio 3?)

Contact Information

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SPP Staff White Paper on Analytical Methods for Unintended Consequence Review

RARTF Meeting
August 4-5, 2011
Dallas, Texas

Paul Suskie
psuskie@spp.org 501.688.2535

Helping our members work together to keep the lights on... today and in the future
SPP Staff White Paper for RARTF.

SPP Staff White Paper is divided into 3 Sections

- Section 1 – Contains an overview of SPP Tariff Requirement
- Section 2 – Contains SPP Staff’s research
- Section 3 – Contains SPP Staff’s recommendations

SPP Staff White Section 1

- Section 1.1 - Overview of SPP Tariff Requirements
- Section 1.2 - Cost Allocation Challenges for Transmission Upgrades
SPP Staff White Section 2.

- Section 2.1 - SPP Staff Research for this White Paper
- Section 2.2 - Transmission Cost Allocation Methods in the United States and SPP
- Section 2.3 - Methods of Measuring Transmission Upgrade Benefits

SPP Staff White Section 3.

- Section 3.1 - SPP Staff Recommendations For Unintended Consequences Review
- Section 3.2 - SPP Staff Recommendation: Three -Tiered Benefit Analysis Approach
- Section 3.3 - SPP Staff Recommends Analyzing Transmission Projects in 4 Stages
- Section 3.4 - Unintended Consequences Threshold
- Section 3.5 - Proposed Unintended Consequences Mitigation
- Section 3.6 - Proposed Unintended Consequences Review Timeline
Section 1.1 – SPP Tariff Requirements

• Step 1: One year prior to each three-year planning cycle (starting in 2013) the Markets and Operations Policy Committee and Regional State Committee will define the analytical methods to be used to report under this Section III.D and suggest adjustments to the Regional State Committee and Board of Directors on any imbalanced zonal cost allocation in the SPP footprint.

Section 1.1 – SPP Tariff Requirements

• Step 2: For each review conducted in accordance with Section III.D.1, the Transmission Provider shall determine the cost allocation impacts of the Base Plan Upgrades with Notifications to Construct issued after June 19, 2010 to each pricing Zone within the SPP Region. The Transmission Provider in collaboration with the Regional State Committee shall determine the cost allocation impacts utilizing the analysis specified in Section III.e of Attachment O and the results produced by the analytical methods defined pursuant to Section III.D.4(i) of this Attachment J.
Section 1.1 – SPP Tariff Requirements

• Step 3: The Transmission Provider shall review the results of the cost allocation analysis with SPP’s Regional Tariff Working Group, Markets and Operations Policy Committee, and the Regional State Committee. The Transmission Provider shall publish the results of the cost allocation impact analysis and any corresponding presentations on the SPP website. Attachment J, Section III.D.3 of SPP’s OATT.

Section 1.1 – SPP Tariff Requirements

• Step 4: The Transmission Provider shall request the Regional State Committee provide its recommendations, if any, to adjust or change the costs allocated under this Attachment J if the results of the analysis show an imbalanced cost allocation in one or more Zones.
Section 1.2 – Cost Allocation Challenges

“Determining the costs and benefits of adding transmission infrastructure to the grid is a complex process, particularly for projects that affect multiple systems and therefore may have multiple beneficiaries. At the same time, the expansion of regional power markets and the increasing adoption of renewable energy requirements have led to a growing need for transmission projects that cross multiple utility and RTO systems. There are few rate structures in place today that provide the allocation and recovery of costs for these intersystem projects, creating significant risk for developers that they will have no identified group of customers from which to recover the cost of their investment.”

FERC Transmission Planning Processes Under Order No. 890, Notice of Request for Comments at 5, Docket No. AD09-8-000 (Oct. 8, 2009).

Section 2.2 – Cost Allocation Methodologies
Section 2.2 – SPP Cost Allocation Methods

Summary of Southwest Power Pool’s Cost Allocation Methods

<table>
<thead>
<tr>
<th>Date Range</th>
<th>Upgrade Type</th>
<th>Zonal</th>
<th>Regional</th>
<th>Transmission Customer</th>
<th>Sponsor</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-2009</td>
<td>Pre-BPF Needs</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Other</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2005- NTC Issue Date of June 19, 2010</td>
<td>Sponsored</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Reliability</td>
<td>67%</td>
<td>33%</td>
<td>Based on Need-By Date Zone on MW-MI</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Generation Interconnection</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>TSR - Designated Resource Under Safe Harbor</td>
<td>07%</td>
<td>33%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>TSR - Designated Resource Over Safe Harbor</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>TSR - Non Designated Resource</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Balanced Portfolio</td>
<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NTC Issue Date of June 19, 2010 through the Present</td>
<td>Sponsored</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Upgrade Voltage Over 500 kV</td>
<td>0%</td>
<td>100%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Upgrade Voltage over 100 kV and under 300 kV</td>
<td>07%</td>
<td>33%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Upgrade Voltage under 100 kV</td>
<td>100%</td>
<td>0%</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>GI</td>
<td></td>
<td></td>
<td></td>
<td>100%</td>
<td></td>
</tr>
</tbody>
</table>

Section 2.3 – Methods of Measuring Benefits

- Improves access to lower-cost generation by reducing grid “bottlenecks”
- Helps add renewable wind and solar energy to grid
- High voltage transmission “superhighways” would move more power more efficiently over long distances at lower costs
- Lower voltage transmission “byways” still needed to move power to smaller distribution lines
- Environmental and land use benefits
- More efficient use of existing resources may reduce need for new generation
- New economic opportunities
- More efficient electricity delivery
- Building “bigger” can be more cost-effective than building to meet minimum requirements
- May reduce electricity reserves, allowing more generation into regional energy market
- Improved reliability reduces high-cost of brown and blackouts
- Diverse fuel usage increases reliability and flexibility
Section 2.3 – Methods of Measuring Benefits

- Adjusted Production Cost
- Meeting State and Utility Goals and Standards
- Improvements in Reliability
- Enable Efficient Location of New Generation Capacity
- Reduced Losses
- Increased Effective Capacity Factor
- Ability to Reduce Cost of Capacity
- Positive Impact on Capacity Required for Losses
- Levelization of Locational Marginal Price
- Improved access to economical resources participating in SPP markets
- Change in operating reserves
- Transmission Loading Relief (TLR) Reduction - Enabling Market Solutions
- Improvements to Import/Export Limits
- Improved economic market dynamics not measured in the security constrained economic dispatch model
- Improved economic market dynamics measured in the nodal security constrained economic dispatch model
- Reduction in market price volatility
- Reduction of emission rates and values
- Transmission corridor utilization
- Ability to reduce cycling of base load units
- Generation resource diversity
- Part of overall EHV Overlay Plan
- Ability to serve unexpected new load

Section 3.1 – SPP Staff REcommendation

- Based upon research and experience, SPP staff recommends that the Unintended Consequences review contain two components. First, a three-tiered analytical methodology evaluating different benefits will be considered. Second, the review should be conducted looking at transmission projects in stages.
Section 3.2 – Recommendation: 3-Tiered Approach

- Because both a too conservative approach and a too broad approach to analyzing benefits of transmission projects can be problematic, SPP staff proposes using a three-tiered approach that utilizes three perspectives for transmission benefit assessment. As described below, these methods include a type of method with conservative benefits, moderate benefits, and broad benefits. These methodologies are incremental and contemplate benefits from the prior tier, i.e., the moderate approach considers all benefits from the conservative approach, plus additional value metrics. The three recommended methodologies are discussed below.

Section 3.2 – 1st Conservative Approach

- The first tiered approach is the conservative approach. This approach consists of using the following metrics:
  - Dispatch Savings,
  - Loss Reductions,
  - Avoided Projects,
  - Applicable Environmental Impacts,
  - Reduction in Required Operating Reserves, and
  - Interconnection Improvements.

* Note: The proposed conservative approach comes directly from Attachment O, Section III.8.e to the SPP OATT.
Section 3.2 – 1st Conservative Approach

• Adj Prod Cost = Production Cost - Revenue from Sales + Cost of Purchases

• Where:
  • Revenues from Sales = MW Export x Zonal LMP\textsubscript{Gen} Weighted
  • and
  • Cost of Purchases = MW Import x Zonal LMP\textsubscript{Load} Weighted

Section 3.2 – 2nd Moderate Approach

• The second tiered approach is the moderate approach. This approach consists of using the methodology from the conservative approach, but adds the following benefit metrics: Meeting State and Utility Goals and Standards,
  – Positive Impact on Capacity Required for Losses, and
  – Improvements in Reliability.
Section 3.2 – 2\textsuperscript{nd} Moderate Approach

- **Value of improved ATCs of the SPP grid**: This metric provides a non-monetized (qualitative) assessment of the added flexibility for the potential redirection of power flows within SPP made possible by ATC increases. The challenge in defining this metric is the development of a meaningful weighting structure of ATC defined for multiple combinations of points of receipt and points of delivery.

- **Value of providing a backstop to a catastrophic event**: This metric provides a qualitative assessment of improved grid reliability and its ability to withstand the impact of catastrophic events electrically expressed as multiple contingencies. This metric requires the assessment of catastrophic events and the determination of their probability.

Section 3.2 – 3\textsuperscript{rd} Broad Approach

- This approach consists of using the methodology from the moderate approach, but adds to it the metric of Societal Benefit... These benefits include, but are not limited to, the following:
  - Overall economic output during construction,
  - Overall jobs impact during construction,
  - Additional earnings related to construction jobs impact,
  - Overall economic output during operation,
  - Overall jobs impact during operation,
  - Additional earnings related to operation jobs impact, and
  - Tax benefits to the state.
Section 3.3 – Analyzing Projects in 4 Stages

- SPP staff recommends that the Unintended Consequence analysis be conducted on transmission projects at varying stages in time over a 40-year timeframe. Staff’s recommendation is that the analysis be conducted in four stages:
  - (1) projects in-service at the time of the study,
  - (2) projects projected to be in-service in 6 years,
  - (3) projects projected to be in service in 10 years; and
  - (4) projects projected to be in service in 20 years.
* The 6, 10, and 20-year stages mirror SPP’s planning timelines defined in SPP’s OATT.

Section 3.4 – Unintended Consequences Threshold

- Per the request of the RARTF, SPP staff recommends that an Unintended Consequences threshold be established. This threshold will define when an Unintended Consequences determination will trigger zonal mitigation. If a zone is determined to be below this threshold, mitigation may be necessary to prevent undue unintended consequences.
- It is recommended that the threshold utilized for the Unintended Consequences take a broad look at the overall benefits for each of the recommended stages and metric methods considered for the analysis. In other words, the threshold will apply to the 40-year analysis of the four stages of transmission projects using the three-tiers of assessed benefits.
Section 3.4 – Unintended Consequences Threshold

- SPP staff recommends that an initial threshold be set at a .8 B/C ratio for the conservative-tiered analysis, and .9 B/C ratio for the moderate-tiered analysis, and a 1.0 B/C ratio for the broad-tiered analysis. These ratios will be applied to each of the tiered approaches over the four proposed stages, that is to say, each tier will be summed up from the current year through year 20. This number will be averaged for each tier to represent a final value. This value will be compared to the threshold index chosen for each tier and given a pass/fail result. If a zone passes the analysis for a minimum of two-thirds of the categories, then it is determined to have no unintended consequences. The chart below shows how staff proposes that the threshold will work.

### Proposed Analytical Approaches for the RARTF

<table>
<thead>
<tr>
<th>Solve: B/C Ratios by Tier</th>
<th>Conservative</th>
<th>Moderate</th>
<th>Broad</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stage 1: In-Service</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stage 2: ITP Near Term</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stage 3: ITP10</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stage 4: ITP20</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Threshold</td>
<td>0.8</td>
<td>0.9</td>
<td>1</td>
</tr>
<tr>
<td>Pass/Fail?</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Section 3.4 – Unintended Consequences Mitigation

• If the results for a zone are below an Unintended Consequences threshold, mitigation may be implemented to reduce negative zonal impacts. SPP staff recommends that, in addition to the current authority of the RSC on Cost Allocation issues, the following mitigation techniques may be used to alleviate unintended consequences:
  – Acceleration of already planned upgrades required to bring benefits to a deficient zone earlier to offset unintended consequences of other upgrades;
  – Issuance of NTCs for selected new upgrades required to bring benefits to a deficient zone to offset unintended consequences of other upgrades; and
  – Zonal Transfers (similar to Balanced Portfolio Transfers) to offset costs or a lack of benefits to a zone to offset unintended consequences.

Section 3.5 – Proposed Timeline
Annual Transmission Revenue Requirement

ATRR: What is it, Why it Matters and How is it calculated?

Annual Transmission Revenue Requirement

• What is it?
• Why it matters.
• How is it calculated.
• A Simple Example.
ATRR: What is It?

• The Annual Transmission Revenue Requirement (ATRR) is the amount of Revenue that the Transmission Owner receives from SPP for RECOVERY OF its expenses (Cost of Debt, O&M, Depreciation, Taxes) for the project and EARNINGS ON the project (Return On Equity).

• ATRR set in a Section 205 filing with the FERC for jurisdictional utilities or in a rate filing a state commission.
  – By either a ‘Stated Rate’ or ‘Formula Rate’

ATRR: Why it Matters

Year 0

$ATRR_n = \text{Net Plant} \times \text{Net Plant Carrying Charge (NPCC) of Transmission Owner building Project)}$

until Project is fully depreciated

Example: Year 0

\[\begin{align*}
\text{Net Plant} &= $100 \text{ million Project} \\
\text{NPCC} &= 16\% \\
\text{Depreciation} &= $0 \\
\text{Life} &= 40 \text{ years} \\
\text{ATRR}_0 &= $100M \times 16\% = $16M
\end{align*}\]
ATRR: Why it Matters

Year 1

\[ \text{ATRR}_n = \text{Net Plant} \times \text{Net Plant Carrying Charge (NPCC) of Transmission Owner building Project)} \]

Example: Year 1

Net Plant = $100M Project
NPCC = 16%
Depreciation = $2.5M
Life = 40 years

\[ \text{ATRR}_1 = \$97.5M \times 16\% = \$15.6M \]

ATRR: Why it Matters

Year 2

\[ \text{ATRR}_n = \text{Net Plant} \times \text{Net Plant Carrying Charge (NPCC) of Transmission Owner building Project)} \]

Example: Year 2

Net Plant = $100M Project
NPCC = 16%
Depreciation = $2.5M

\[ \text{ATRR}_2 = \$95.0M \times 16\% = \$15.2M \]
ATRR: How is it calculated?

\[ \text{ATRR}_n = \text{Net Plant} \times \text{Net Plant Carrying Charge (NPCC) of Transmission Owner building Project} \]

\[ n = 1, 40 \text{ (or other depreciable life of Asset)} \]

Net Plant = Cost of Project – Accumulated Depreciation

Net Plant Carrying Charge = Weighted Average Cost of Capital + O&M + Taxes + Depreciation

ATRR: How is it calculated?

• Net Plant Carrying Charge = Weighted Average Cost of Capital + O&M + Taxes + Depreciation
• Weighted Average Cost of Capital (WACC) = Cost of Debt * Debt/Equity ratio + Return On Equity (ROE) * (1 – Debt/Equity ratio)

In Example:
• WACC = 8%*(.5) + 11%*(.5) = 9.5%
• NPCC = 9.5% + 4% + 2% + 2.5% = 16%
ATRR: Effect of Depreciation Over Time

Effect on Net Plant over time due to Accumulated Depreciation
Annual Transmission Revenue Requirement

ATRR: What is it, Why it Matters and How is it calculated?