CAWG’S RECOMMENDATIONS TO THE RSC REGARDING MWG’S TCR PROPOSALS

October 26, 2010
Mike Proctor
The CAWG proposals at the July, 2010 RSC Meeting:

**Recommendation 1: LTFTRs**
- In the future consideration of long-term firm transmission rights (LTFTRs), the MWG should revisit whether or not the first stage of the allocation of annual ARRs should be restricted to base-load generation with capacity factors > 50% and long-term firm PTP with a loading factors > 50%.
- The MWG should make recommendations on LTFTRs in time to implement LTFTRs one year after the start of the day-ahead markets.

**Recommendation 2: Infeasible ARRs for Base-Load Resources**
- [The CAWG recommended] Waiting to see the results from the allocations from the first annual ARR auction prior to the implementation of LTFTRs, and when the MWG takes up the LTFTR issue it should evaluate the issue of TCs not able to get ARRs for base-load requirements.

**Recommendation 3: Participation in TCR Auctions by Non-Transmission Customers**
- Assuming sufficient financial protections (as determined by the SPP credit standards and approved by the RSC) are put in place for non-transmission customers to participate in TCR auctions, the RSC should approve participation by any entity that meets the required financial protections.

**Recommendation 4: Managing the Risk of Default**
- The buyer’s payments for its purchase of an infeasible TCR should not be paid by the SPP to the seller until the seller makes good on its commitment to pay the congestion costs. If the seller defaults on its obligation to pay, then the buyer’s payment to the SPP should be refunded.
The RSC asked to CAWG to perform additional analysis on the profit taking reported for the MISO monthly FTR auctions.

The CAWG presented that analysis at the October 6, 2010 RSC Teleconference meeting.

The RSC affirmed the CAWG’s recommendation to allow non-transmission customer to participate in SPP’s TCR auctions.
Further Recommendation

- At the October 6 RSC teleconference call, the CAWG also made the following recommendation to the SPP:

  - To eliminate confusion and to properly track profit taking, the SPP should calculate profit taking in the TCR auctions:
    - Separately for Forward TCRs and Counterflow TCRs.
    - Separately for Transmission Customers and non-Transmission Customers for Forward TCRs.
The CAWG recommends that the RSC affirm the TCR design set forth by the MWG, including the allocations of the TCRs, subject to the five recommendations summarized above.
REFRESHER ON INCLUDING WIND REVENUES AS BENEFITS

October 26
Mike Proctor
Review of Decisions Made Regarding Treatment of Wind Resources in Priority Projects

- Originally SPP ran its cost-benefit analysis with new wind resource being excluded from the base case.
  - This treats wind as “market-based” resources that would not find it economic to be built without the construction of the Priority Projects.

- The SPC directed SPP to include wind resources in the base case.
  - This treats wind as “designated” resources that could participate in the base case - assuming a contract with load and a load that is willing to pay the resulting costs that would be incurred without the Priority Projects.
Economics of Wind Production

At the January 6, 2010 CAWG meeting detailed presentations of the economics of wind production were made. The following is a summary/conclusion from that meeting.

- Notice that the Annual Revenue Requirements (ARR)\(^1\) is the same irrespective of the capacity factor (CF) that is assumed in the Before and After new transmission cases.

- However, with the lower capacity factor in the Before case, the MWhs over which the ARR is collected is lower, the production tax credits are lower and therefore the $/MWh received from sales of the energy must be higher in order to recover these costs.

- This means that in the base (Before) case the cost per MWh to the load contracting for wind will be higher than in the change (After) case – assuming that the capacity factors and/or prices for wind generation increase.

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1. ARR refers to the amount of dollars that needs to be paid to a wind resource to recover its costs.
The following is the conclusion presented at the CAWG Jan 6, 2010 meeting:

- **Priority Projects:** Net Benefits for Required Renewable Energy Resources (RRERs) not designated as resources
  \[
  = (\Delta \text{MWh} \times \text{Production Tax Credit}) + (\text{RRER Rev}_{\text{After}} - \text{RRER Rev}_{\text{Before}})
  \]

- These benefits should be added to the benefits from the APC Savings to obtain total benefits.

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2. The “not designated as resources” refers to the way SPP ran the APC calculations, not assigning wind resource to loads. This does not mean that these are not “designated” resources. It simply reflects the fact that it would be very difficult, if not impossible for SPP to assign existing “market-based” or new wind at specific locations to specific loads. Instead all wind resources were treated as a separate group.
Why should the change in wind revenues be included as a benefit?

Because it reduces the cost of the wind energy to the load.

- How does that happen?
  - The load either buys the wind resource or enters into *traditional contracts* with the owner purchasing MWhs at a fixed $/MWh.
    - In either case (own or purchase power), the MWhs of wind produced are the property of the load.
    - As the property owner, the load now receives the MWhs of wind produced as energy to serve its load.
  - Alternatively purchased wind power can be viewed as a *contract for differences*, where:
    - The MWhs remain the property of the generator who gets the revenues from the sale of wind into the market.
    - The contract is for a fixed $/MWh minus revenues received from the owner selling the MWhs into the SPP market.
  - For either traditional contracts or contracts for differences, the cost of the wind MWhs goes down when the MWhs go up.
    - The issue raised about including the change in wind revenues as a “benefit” is whether or not the load actually **receives the revenues (contract for differences) or the energy to serve its load (traditional contracts).**
Issue: Since wind power is base loaded, the load does not receive the revenues from the sales.

- It is true that under the traditional contracts, wind as a base-load resource is not being sold in the Adjusted Production Cost (APC) calculations.
  - APC = Production Cost + Purchased Power Cost – Revenues from sales, and base-loaded resource are not included in sales.
  - The APC accounting is that the wind you paid for in the contract and is base loaded displaces:
    - Running higher cost resources; and/or
    - Purchasing other higher cost power; and/or
    - Making more generation available to sell; i.e., higher revenues from sales.

- HOWEVER: SPP did not run its APC calculation with wind resources being assigned to specific loads. Instead, SPP modeled the wind as contracts for differences.
  - Increased wind in the APC calculation for the change case would be reflected as:
    - A decrease in production cost and/or an increase in revenues from sales of own generation not needed to serve load, both due to:
      - An increase in purchased power from wind bought at market price (as if the wind was being purchased from the market) under contracts for differences);
  - Thus, the change in wind revenues needs to be included as a “benefit” to offset the increase in purchased power costs of the wind that is reflected in the calculation of APC savings.
Conclusion

- SPP did not run any of the wind as a resource for specific loads (it could not for existing “market-based” or new wind), and therefore the change in wind revenues should be included as an offset to the increased purchased power costs of the wind that are included in the calculation of APC savings.

- After-the-runs, in order to get some concept of who benefited, I performed a spreadsheet allocation of the change in wind revenues to the various states and the loads within each of the states. These allocations were presented to the CAWG at its February 24, 2010 meeting and revised at its March 30, 2010 meeting.
Action Items Completed

• Tariff Revisions
  • TRR017-Definition of Resident Load
  • TRR018-Election of Loss Compensation
  • TRR019-Loss Calculation
  • TRR027-Change in TO Definition
  • TRR028-Admin Fee Cap Changes
Revenue Requirement Updating

- Current process requires that any change in a TO’s Rev. Req. requires SPP to make a 205 filing
  - Costly
  - Takes time
  - Often times effective date of change is prior to the issue of the final Order requiring rebilling of transmission service
    - Causes big Customer bills
    - Causes delays in revenue distribution for T.O.s
  - 14 T.O.s now have formula rates requiring annual updates
  - BDTF is looking at modifying Tariff to make this process more automatic
  - Rather that specific numbers in Tariff, it would reference a posted Spreadsheet with all the revenue numbers
  - More transparent since all data posted on OASIS, including details not current in the Tariff
  - Might have some 205 filings for T.O.s with a stated Rev. Req.

Crediting Process

- Item: Tariff requires “Credits” to be paid to customers who pay for upgrades
  - Can be from requests for Transmission Service, Generation Interconnections or Sponsored Upgrades

- Working on details with staff on how to calculate credits
  - What is a “Creditable Upgrade”? – (The “but-for” test)
  - How are the credits calculated?
  - When do the credits Stop?

- Result will be a paper outlining the process
  - Target completion date is January, 2011
Questions??
Overview of ESWG

- ESWG consists of 13 voting members representing a cross section of SPP members

- Three liaison members – Sam Loudenslager APSC, Jim Sanderson KCC, and Mike Proctor RSC

- Additional consistent stakeholder involvement from others as well – Adam McKinnie and Walt Cecil of the MPSC, wind coalition, others
ESWG ITP Progress as of 7/26/10

- Base case resource plan developed
- ITP Planning Manual in development
- Consultant retained to develop calculation methods for remaining metrics
- Robustness whitepaper under review

ESWG ITP Progress since 7/26/10

- Resource plans for four futures developed
- ITP Planning Manual completed by ESWG/TWG/RTWG and endorsed by MOPC – subject to future additions
- Metrics completed for ITP20
- Metrics manual complete – incorporates “Robustness”
Resource Futures

Futures Scenarios

• Uncertainties in forecasting future conditions
  ➢ Policy Considerations
    • Renewable Electricity Standards
    • Carbon Mandates
    • Energy Efficiency
  ➢ Generation Development
  ➢ Load Growth

• Multiple futures enables a flexible expansion plan that will be versatile under many possible future scenarios
Futures Development

- Futures defined by the SPC
- Developed by referencing the CAWG state’s renewable survey
- ESWG/TWG developed future’s assumptions
  - Carbon Prices
  - Fuel Forecasts
  - Wind Characteristics
  - Load Forecasts

ITP20 Futures

- Future 1: Base Case
  - Current Mandates and Policy
  - Existing Renewable Targets (10.5 GW)

- Future 2: Renewable Electricity Standard (RES)
  - Federal 20% RES* (16.5 GW)
  - No Carbon Price

* - Assumes all load is subject to federal RES
ITP20 Futures

- **Future 3: Carbon Mandate**
  - Carbon Tax ($49 in 2010 dollars)
  - Current Mandates and Policy
  - Existing Renewable Targets (10.5 GW)

- **Future 4: Carbon Mandate and RES**
  - Carbon Tax ($49 in 2010 dollars)
  - Federal 20% RES* (16.5 GW)

* - Assumes all load is subject to federal RES

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Resource Plan Overview

- Developed by Black & Veatch
- Unique resource plan per future (4)
- ESWG approved July 28th
- MOPC review Aug 20th
Resource Plan

- 20 year levelized costs
- Least cost solution
  - Base-load units
  - Intermediate units
  - Peaking units
- ESWG Siting Criteria

Capacity Expansion

- Capacity margin requirement of 12%
- Wind Capacity counted as 5% of nameplate
- Generation expansion conducted on a sub-regional basis
Capacity Requirements

2030 Resource Plan Needed to Maintain Capacity Margin

- Capacity Margin
- Minimum Capacity Margin Threshold
- Capacity Needed

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Resource Mix for Each Future

2030 Resource Mix Additions by Technology for Each Future (MW)

- Wind
- Coal
- Combustion Turbine
- Combined Cycle

Future 1: 16,664 MW
  - Wind: 16,664 MW
  - Coal: 0 MW
  - Combustion Turbine: 0 MW
  - Combined Cycle: 0 MW

Future 2: 12,754 MW
  - Wind: 12,754 MW
  - Coal: 0 MW
  - Combustion Turbine: 0 MW
  - Combined Cycle: 0 MW

Future 3: 10,034 MW
  - Wind: 10,034 MW
  - Coal: 0 MW
  - Combustion Turbine: 0 MW
  - Combined Cycle: 0 MW

Future 4: 13,774 MW
  - Wind: 13,774 MW
  - Coal: 0 MW
  - Combustion Turbine: 0 MW
  - Combined Cycle: 0 MW
ITP Manual

- Started March 2010 to outline and document the ITP process
- Endorsed by TWG, Sept. 2010 and ESWG, Oct. 2010
- RTWG review Sept 2010 for tariff compliance
- Endorsed by MOPC at Oct 12-13 meeting, subject to future additions
Metrics

MTF and ESWG Robustness Metrics Work

- ESWG created the Metrics Task Force (MTF)
- MTF developed list of metrics
  - 15 Metrics, Metric 1 has 6 sub-metrics
  - Provided brief description of metrics for further development
- ESWG, MOPC approved metrics to for the ITP20
CRA Metric Development

• Charles Rivers & Associates (CRA) contracted for metric development
• Based on MTF results
• CRA was tasked with further developing the metrics including:
  • Formulas
  • Monetization
  • Enhanced Definitions

ITP20 Metrics Manual

• Developed by CRA
• Reviewed by the ESWG
• Metric details provided:
  • Description and Purpose
  • Model/Tool description
  • Data requirements
  • Calculation/Formulas
  • Step-by-Step process
  • Example
Adjusted Production Cost

• All projects were evaluated for their production cost benefit
• Included in APC:
  • Fuel costs
  • Emissions
  • Congestion
  • Marginal prices
• Not included in APC:
  • Reliability
  • Transfer capability
  • Geographic information

Metrics - continued

• Charles Rivers & Associates (CRA) contracted for metric development
• Based on MTF results
• CRA was tasked with further developing the metrics including:
  • Formulas
  • Monetization
  • Enhanced Definitions
Metrics – continued

• Metric 1 - Added value not previously quantified
  • 6 submetrics – improved reliability, enable efficient location of new generation, reduced losses, increased effective capacity factor, ability to reduce cost of capacity, positive impact on losses capacity

• Metric 2: Levelization of LMPs

• Metric 3: Improved Competition in SPP Markets

• Metric 4: Change in the Installed Capacity Margin (net yet in – further development needed)

Metrics – continued

• Metric 5: TLR Reduction/Enabling Market Solutions (not done for ITP20)

• Metric 6: Limited Export/Import Improvements

• Metric 7: Improved Market Dynamics NOT measured in Promod (not done for ITP20)

• Metric 8: Improved Market Dynamics measured in Promod (not done for ITP20)

• Metric 9: Reduction in Market Price Volatility (not done for ITP20 – will require enhanced calculation methods)
Metrics – continued

- Metric 10: Reduction of Emission Rates and Values
- Metric 11: Transmission Corridor Utilization
- Metric 12: Ability to Reduce Cycling of Base load units (not done for ITP20)
- Metric 13: Generation Resource Diversity
- Metric 14: Ability to Serve New Load

Next Steps
ESWG Near-Term Priorities

• Finish review of ITP20 plan and report
  • Draft report has been posted and with comments solicited from stakeholders
  • SPP is scheduling a joint ESWG/TWG planning meeting for mid-December

• Metric Weighting
  • Develop a weighting system for metrics by mid-December

• Develop Scope for ITP10 Study
  • Jointly with TWG – scheduled for mid-December

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Appendix – Rubustness Metric Descriptions

Metric I: Added value not previously quantified

- 6 Sub-metrics
- Sub-Metric 1: Improved Reliability (3 Parts)
  - Value of delaying or eliminating the need for previously approved reliability projects
  - Value of improved Available Transfer Capabilities (ATCs)
  - Other values such as a backstop to catastrophic event
Sub-Metric II: Enable Efficient Location of New Generation

- Measures the value of transmission accessing high generation value areas
  - High capacity factor wind areas
  - Greenfield sites for conventional generation

Sub-Metric III: Reduced Losses

- Measure the effect of reduced losses from new transmission lines

Sub-Metric IV: Increased Effective Capacity Factor

- Measures the effect of reduced curtailments on generation

Sub-Metric V: Ability to Reduce Cost of Capacity

- Operating/spinning reserves
Sub-Metric VI: Positive Impact on Losses Capacity

- Captures the change in capacity necessary to cover losses
- A decrease in losses may represent a reduction in generation capacity needs

Metric 2: Levelization of LMPs

- Qualitative indicator on how LMPs level across the footprint
  - Reduction high price load pockets
- Calculated for Load and Gen LMPs
- A measure of competition across the footprint
  - The lower the standard deviation in LMP the more competition
Metric 3: Improved Competition in SPP Markets

- Qualitative measure of competitiveness
  - Focus on generation weighted LMPs
- Competitiveness among generation types (steam coal, CT, CC, wind)

Metric 4: Change in the Installed Capacity Margin

- Improved power transfer potentially reduces capacity margin requirements
- Monetized using the savings in capital and fixed O&M

Metric 5: TLR Reduction/Enabling Market Solutions

- Examine reduction in TLR due to transmission solutions
Metric 6: Limited Export/Import Improvements

• Quantifies the change in ATC
  • From SPP gen centers to delivery points on the SPP boundary
  • From external gen centers on the SPP boundary to SPP load
  • From external gen centers on the SPP boundary to external load (wheel-through transactions)

Metric 7: Improved Market Dynamics

NOT measured in Promod

• Examines potential market power issues

Metric 8: Improved Market Dynamics

measured in Promod

• Measures average marginal costs within the SPP footprint
Metric 9: Reduction in Market Price Volatility

• Evaluate the response of market prices to changes in inputs for different transmission plans

Metric 10: Reduction of Emission Rates and Values

• Quantify the change in emissions
  • Captured in lbs per MWh
  • Cost of CO$_2$, SO$_2$, and NO$_x$ is captured in APC
**Metric 11: Transmission Corridor Utilization**

- **New Right-of-Way (ROW)**
  - Miles of new ROW necessary for the additional transmission
- **Environmentally Sensitive Areas**
  - Miles of ROW which pass through environmentally sensitive areas

**Metric 12: Ability to Reduce Cycling of Base load units**

- Measures cycling of units

**Metric 13: Generation Resource Diversity**

- Measure the effect of more diverse mix
  - Less exposure to fuel price fluctuations
Metric 14: Ability to Serve New Load

- Ability of transmission to serve new unexpected load
Why are we here?

- Aging infrastructure
- Growing need for transmission
- Markets
- Seams
- Dynamic policy climate
  - Demand response
  - Renewable mandates
  - Smart grid
ITP20 Performance Goals

- Integrate west to east
- Support queues
  - Aggregate Transmission Service
  - Generator Interconnection
- Relieve known congestion

ITP20 Expectations

- Robust EHV expansion plan for the SPP region
  - Identified through analysis of multiple futures.
  - What it is:
    - Long-term, robust EHV expansion plan
    - Value-based, cost-effective solution
    - Considers both economics and reliability
    - A piece of the ITP pie
ITP10 and IPT NT

- **What it is:**
  - Covers all potential reliability issues
    - Covered in ITP10 and ITPNT
  - Ensures total deliverability of wind
    - Covered through GI and TSR studies
  - Solution to local area reliability issues
    - Covered in ITPNT

ITP20 Process

- **Four futures (SPC)**
  1. Business as usual
  2. RES
  3. Carbon Mandate
  4. Carbon Mandate + RES

- Developed one least cost plan (LCP) for each future
- Cost Effective Plan
- Robustness Plans
LCP: Business As Usual

- No Carbon Tax
- No Federal RES
- CAWG Survey
- Same transmission development as SPP.org

LCP: Carbon Mandate

- Carbon Price of $49
- No Federal RES
- CAWG Survey
- Same transmission development as Business As Usual
LCP: RES

- 20% Federal RES
- No Carbon Tax
- Similar transmission development to RES/Carbon Mandate Future

LCP: RES/Carbon Mandate

- 20% Federal RES
- Carbon Price of $49
- Similar transmission development to RES Future
Cost Effective Plan Development

- Projects common to all four plans
- Evaluated remaining least-cost projects
  - Weighed the economic benefit against the estimated transmission cost of each project
- Cost-Effective Plan: B/C > 1
  - All four futures
- Meets SPPT Goals
Robustness Assessment

- **Metrics**
  - 10 Robustness
  - APC

- **Cost-Effective Plan**
  - All 4 futures

- **New projects**
  - Incremental value

Robustness Metric Scoring

- **Normalized**
  - 100 scale

- **Top Plan**
  - Score of 100

- **Other plans**
  - Compared to top performing plan
### Robustness Analysis

#### Cost (millions)

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#### APC B/C

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#### Levelization of LMP’s

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#### Improved Competition in SPP Markets

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#### Improved Reliability

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#### Ability to Serve New Load

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#### Limited Export/Import Improvements

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#### Enable Efficient Location of New Generation Capacity

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#### Reduction of Emissions Rates and Values

<table>
<thead>
<tr>
<th></th>
<th>Robust Plan 1</th>
<th>Robust Plan 2</th>
<th>Robust Plan 3</th>
<th>Robust Plan 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reduction of Emissions Rates and Values</td>
<td>97.8</td>
<td>99.6</td>
<td>99.1</td>
<td>100.0</td>
</tr>
</tbody>
</table>

#### Transmission Corridor Utilization (ROW)

<table>
<thead>
<tr>
<th></th>
<th>Robust Plan 1</th>
<th>Robust Plan 2</th>
<th>Robust Plan 3</th>
<th>Robust Plan 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Corridor Utilization (ROW)</td>
<td>95.0</td>
<td>100.0</td>
<td>85.4</td>
<td>94.1</td>
</tr>
</tbody>
</table>

#### Transmission Corridor Utilization (Env. Sensitive Areas)

<table>
<thead>
<tr>
<th></th>
<th>Robust Plan 1</th>
<th>Robust Plan 2</th>
<th>Robust Plan 3</th>
<th>Robust Plan 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Corridor Utilization (Env. Sensitive Areas)</td>
<td>95.8</td>
<td>100.0</td>
<td>92.8</td>
<td>91.9</td>
</tr>
</tbody>
</table>

#### Robustness Metric Average

<table>
<thead>
<tr>
<th></th>
<th>Robust Plan 1</th>
<th>Robust Plan 2</th>
<th>Robust Plan 3</th>
<th>Robust Plan 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Robustness Metric Average</td>
<td>92.0</td>
<td>91.3</td>
<td>83.0</td>
<td>98.6</td>
</tr>
</tbody>
</table>

### Robust Plan 4

- **Similar corridors to Cost-Effective Plan**
- **Total ITP20 E&C = $7.3B**
- **B/C of .47**
**Robust Plan 1**

- Cost-Effective Plan = $1.7B
- Robust project additions = $681M
- Total ITP20 E&C = $2.4B
- B/C = 1.6

---

**Robust Plan 1**

- B/C of 1.6
- Project in every state
  - SPP TO states
- Low E&C cost
- Performs well in every metric
- Best 345 kV plan
  - Leveling LMPs
  - Improving Competition

---

**Southwest Power Pool**

<table>
<thead>
<tr>
<th>Metric</th>
<th>Score</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost (millions)</td>
<td>$2.383</td>
</tr>
<tr>
<td>APC B/C</td>
<td>1.59</td>
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<tr>
<td>Levelization of LMP's</td>
<td>86.5</td>
</tr>
<tr>
<td>Improved Competition in SPP Markets</td>
<td>81.1</td>
</tr>
<tr>
<td>Improved Reliability</td>
<td>94.4</td>
</tr>
<tr>
<td>Ability to Serve New Load</td>
<td>99.3</td>
</tr>
<tr>
<td>Limited Export/Import Improvements</td>
<td>97.6</td>
</tr>
<tr>
<td>Enable Efficient Location of New Gen Capacity</td>
<td>94.8</td>
</tr>
<tr>
<td>Reduction of Emissions Rates and Values</td>
<td>97.9</td>
</tr>
<tr>
<td>Transmission Corridor Utilization (ROW)</td>
<td>96.2</td>
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<tr>
<td>Losses Capacity</td>
<td>95.8</td>
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<tr>
<td>Transmission Corridor Utilization</td>
<td>98.5</td>
</tr>
<tr>
<td>Robustness Metric Average</td>
<td>95.4</td>
</tr>
</tbody>
</table>
Robust Plan 1

Cost (billions)

- Plan 1: $2.4
- Plan 2: $3.1
- Plan 3: $1.8
- Plan 4: $7.3

B/C

- Plan 1: 1.6
- Plan 2: 1.2
- Plan 3: 2
- Plan 4: 0.5

Robust Metric Score

- Plan 1: 92
- Plan 2: 91
- Plan 3: 83
- Plan 4: 99

Next Steps for Staff

- Limited Reliability Assessment
- 40-Year Financial Analysis
- Stability Loadability Studies
- Zonal and State benefit calculation
- Plan refinement
  - Stakeholder feedback
- Additional metric calculation
- Rate Impacts
- Unintended consequences