Integrated Resource Plan Period

Integrated Resource Plan

1 year  5 year  10 year  20 year  50 year  100 year
Integrated Resource Plan (IRP)

- Identify sufficient resources to reliably serve the area energy demand through a 20-year period
- Balance cost, risk, and environment
- Equal treatment of supply-side resources, demand-side measures, and transmission resources
- Biennial analysis of a resource stack to effectively balance loads & resources
Transmission Modeling in the IRP

- IRP analysis solves a Power Cost Model for the entire West – selecting the lowest cost resources to serve the load
- Constrained transmission in the model will limit the ability to transfer energy from certain resources to the load
- Transmission additions that reduce these constraints will allow for a more economic dispatch of resources
## IRP & Transmission Plan Comparison

<table>
<thead>
<tr>
<th>Planning</th>
<th>Integrated Resource Plan</th>
<th>Transmission Plan</th>
</tr>
</thead>
<tbody>
<tr>
<td>Objective</td>
<td>Resource Sufficiency</td>
<td>Service Reliability</td>
</tr>
<tr>
<td>Period</td>
<td>20 years</td>
<td>1, 5, 10, 20 and 100+ years</td>
</tr>
<tr>
<td>Driver</td>
<td>8760 demand</td>
<td>Peak annual demand</td>
</tr>
<tr>
<td>Considerations</td>
<td>Capacity and Energy</td>
<td>Capacity</td>
</tr>
<tr>
<td>Factors</td>
<td>Cost, risk, and environment impact</td>
<td>Cost and siting impact</td>
</tr>
<tr>
<td>Analysis</td>
<td>Production Cost</td>
<td>Power Flow</td>
</tr>
</tbody>
</table>
Local Planning
Area Electric Plans
Community Advisory Committees
Planning Periods

- 1 year
- 5 year
- 10 year
- 20 year
- 50 year
- 100 year

Area Electric Plan
Afghan Transmission Line Protest
Build Understanding

- Describe need
- Develop siting criteria
  - Along major transportation corridors
  - Avoid schools, downtown, etc.
Buildout

Land

Water
Assign load density (MW/mi²) to land use/zoning designations

<table>
<thead>
<tr>
<th>Zoning Description</th>
<th>Load Density (MW/mi²)</th>
<th>Zone Area (mi²)</th>
<th>Load (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Agricultural</td>
<td>0.4</td>
<td>2</td>
<td>0.8</td>
</tr>
<tr>
<td>Residential</td>
<td>5</td>
<td>1</td>
<td>5</td>
</tr>
<tr>
<td>Industrial</td>
<td>45</td>
<td>1</td>
<td>45</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>4</td>
<td>50.8</td>
</tr>
</tbody>
</table>
Electrification
## Buildout Demand

<table>
<thead>
<tr>
<th>County</th>
<th>Current Demand (MW)</th>
<th>Buildout Demand (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cassia</td>
<td>124</td>
<td>303</td>
</tr>
<tr>
<td>Gooding</td>
<td>75</td>
<td>292</td>
</tr>
<tr>
<td>Jerome</td>
<td>125</td>
<td>524</td>
</tr>
<tr>
<td>Lincoln</td>
<td>37</td>
<td>203</td>
</tr>
<tr>
<td>Minidoka</td>
<td>112</td>
<td>231</td>
</tr>
<tr>
<td>Twin Falls</td>
<td>237</td>
<td>1019</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>710</strong></td>
<td><strong>2572</strong></td>
</tr>
</tbody>
</table>
Develop a Plan Together
Public Involvement
Transmission Planning
Demand Forecasting
Demand Forecasting

95th–Percentile Average Peak-Day Temperature Adjustment

Cubic Regression with Horizon Loads
40 Years – Average Temperature on Peak Day
95\textsuperscript{th}-Percentile Demand

Actual Peak Demand
Cubic Function
Horizon Loads

<table>
<thead>
<tr>
<th>Year</th>
<th>Peak Load (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>7</td>
<td>4</td>
</tr>
<tr>
<td>12</td>
<td>8</td>
</tr>
<tr>
<td>29</td>
<td>6</td>
</tr>
</tbody>
</table>

Fitted Curve

Horizon Year Loads
Transmission Planning Analysis
Line Limits: Conductor Thermal Limits

Southwire company software

Select Conductor

Conductor characteristics

IPC’s Std. environmental assumptions

Conductor current rating
Path Limits: Aggregate of lines

• Limit rating obtained through the WECC Path rating process
  – Open process with analysis reviewed by other WECC entities
• Approved rating when
  – exiting parallel paths are operating at their approved rating and
  – there are no overloaded elements following all credible contingencies*

• Credible contingencies are likely outages of facilities or combination of facilities base on proximity
Example: Idaho to Northwest Path

Line Thermal Limits
- Oxbow-LOLO: 415 MW
- Hells Canyon –Walla Walla: 398 MW
- Brownlee-LaGrande: 370 MW
- Hines-Harney: 50 MW
- Hemingway-Summer Lake: 1500 MW

Sum of individual lines: 2733 MW

Accepted WECC Path Limit: **1200 MW**
## Steady State Voltage Limits

<table>
<thead>
<tr>
<th>Condition</th>
<th>Percent of Nominal Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>System Normal</td>
<td>95 to 105</td>
</tr>
<tr>
<td>Post Contingency</td>
<td>90 to 110</td>
</tr>
<tr>
<td>Post-Contingency deviation from normal</td>
<td>Less than 8</td>
</tr>
</tbody>
</table>
Post Contingency Voltage Change

100 MW
20 MVAR

100% 50 MW 100% 50 MW 99%

100 MW
30 MVAR

100% 0 MW 100% 100 MW 95%

99.98 MW
9.63 MVAR
Voltage Stability

• The ability of power system to maintain steady voltages at all buses in the system after being subjected to a disturbance

• Demonstrated when no voltage collapse occurs under the following:
  • single contingency:
    • flow is increased to 105% of path rating or
    • load is increased to 105% of forecast peak
  • multiple contingencies:
    • flow is increased to 102.5% of path rating or
    • load is increased to 102.5% of forecast peak
Transient Voltage Performance

WECC Criterion - TPL-001-WECC-CRT-3
WR1.4 Example
NORMAL RECOVERY 1

**Normal Recovery 1**

- **Initial Voltage**
- **Voltage recovery above 80% of initial Voltage**

**Bus Voltage Magnitude**

- **80% of initial Voltage**
- **70% of initial Voltage**

**Time duration of Voltage dip below 80% of initial Voltage (shall not remain below 80% for more than 2 seconds)**

**Time duration of Voltage dip below 70% of initial Voltage (shall not remain below 70% for more than 30 cycles)**

**Fault cleared**
Transient Voltage Performance

WECC Criterion - TPL-001-WECC-CRT-3
WR1.4 Example
NORMAL RECOVERY 2

Initial Voltage

Voltage recovery above 80% of initial Voltage

Time duration of Voltage dip below 80% of initial Voltage (shall not remain below 80% for more than 2 seconds)

80% of initial Voltage

Time duration of Voltage dip below 70% of initial Voltage (shall not remain below 70% for more than 30 cycles)

70% of initial Voltage

Fault cleared

Bus Voltage Magnitude

0 Seconds

Time

20 Seconds
Transient Voltage Performance

WECC Criterion - TPL-001-WECC-CRT-3
WR1.3 Example
DELAYED RECOVERY

Initial Voltage

80% of initial Voltage

Fault cleared

Bus Voltage Magnitude

Voltage recovery above 80% of initial Voltage within 20 seconds

Time

0 Seconds

20 Seconds
Trans:ent Stability Analysis

• The ability of the system to maintain synchronism following the occurrence of a short circuit
• Dynamic controls of all generators and inverters modeled in WECC power flow cases to enable stability analysis
• Post fault stability performance driven by:
  – Severity and duration short circuit
  – Local area topology – how tightly connected and robust
  – Response of the generators, inverters and load
Transient Stability: Damped Response
Transient Stability: Less Damped Response
NERC Transmission Planning Reliability Standard TPL-001-4
Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.
TPL-001-4 Requirements

- Annual assessments of transmission system
- 10 year time horizon with different seasons
  - 1 - 2 year Heavy Load & Light Load cases
  - 5 year Heavy Load case
  - 6 - 10 Year Heavy Load case
- Study sensitivity to modeled conditions
- Study impact of spare equipment availability
- Perform contingency analysis
  - Steady State
  - Stability
- Develop corrective action plans for violations

- Audited every three years!
IPC’s TPL-001-4 Assessments

- WECC power flow cases
- Planned projects are included if in-service date is on or before the and year of study
- Known planned outages are modeled
- 40,000 contingencies run
<table>
<thead>
<tr>
<th>Case</th>
<th>Contingency name</th>
<th>Limited element</th>
<th>Violation</th>
<th>Proposed Project</th>
<th>Proposed In-Service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>22hs1_TPL, 22hs1_TPL_stressed_Path_14_55 &amp; 22hs1_TPL_ADEL_XFMR</td>
<td>P2-2_B_KING</td>
<td>MIDPOINT T231</td>
<td>Thermal</td>
<td>Replace T231 at Midpoint with a 300 MVA transformer</td>
<td>2020</td>
</tr>
<tr>
<td>22hs1_TPL, 22hs1_TPL_stressed_Path_14_55 &amp; 22hs1_TPL_ADEL_XFMR</td>
<td>P2-3_BF_BOBN 105Z</td>
<td>GROVE-BOISE 138</td>
<td>Thermal</td>
<td>Cloverdale 230 kV tap</td>
<td>2020</td>
</tr>
</tbody>
</table>
| 22hs1_TPL, 22hs1_TPL_stressed_Path_14_55 & 22hs1_TPL_ADEL_XFMR | P2-3_BF_BOBN 114Z    | BOISEBCH T231 BOISEBCH T232 | Thermal   | Install PCBs at BOBN 233J & 234H positions
Cloverdale 230 kV tap | 2019
2020
Boise Bench Bus Tie Breaker Internal Fault
Proposed Solution

Install two breakers at Boise Bench and connect the Boise Bench-Locust 230 kV line into Cloverdale
Breaker Failure Contingency

204A Breaker Failure
Ontario 230 kV Bus

BLPR

138 kV Bus #2
T232

138 kV Bus #1
T231

Ontario 230 kV Bus

LGSY
## WECC Delegated Responsibilities

<table>
<thead>
<tr>
<th>Compliance</th>
<th>Reliability Planning and Performance Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ensure compliance with NERC reliability standards</td>
<td>Reliability Assessments 0-20 years in the future</td>
</tr>
<tr>
<td>Conduct audits every one to three years</td>
<td>Event Analysis</td>
</tr>
<tr>
<td></td>
<td>Situational Awareness</td>
</tr>
<tr>
<td></td>
<td>Performance Analysis</td>
</tr>
</tbody>
</table>
WECC Role in TPL-001-4

Model Building
• WECC is the Western Interconnection’s power flow and production cost model builder

Reliability Analysis
• WECC uses both models to evaluate reliability risks to the grid

Planning Coordination
• Interconnection-wide planning processes are coordinated (e.g., the path-rating process)
WECC Near-Term Priorities

- **Representation of Inverter-Based Resources**
  - Improve modeling representation
  - Data collection for utility-scale, battery storage and DER

- **Impacts of the Changing Resource Mix**
  - Impacts on path ratings
  - Modeling transmission-distribution interface
  - Impacts on essential reliability services

- **Expansion of RC and Market Service Providers**
  - Potential reliability risks and mitigations
  - Consider regional standards

- **Clarify Roles in BPS Planning**
  - Improve coordination by clarifying roles and responsibilities
Local Transmission Planning
FERC Order 890
FERC Orders 890

• Principles
  – Open, Transparent, etc.
• Process described in our Open Access Transmission Tariff - Attachment K
Local Transmission Planning Period

Local Transmission Plan
Local Transmission Plan Purpose

- Identifies, through the planning horizon, the transmission facility additions and demand resources required to reliably satisfy:
  - Network Customers’ resource and load growth expectations
  - Transmission Provider’s (TP’s) resource and Native Load growth expectations
  - TP’s transmission obligations driven by Public Policy Requirements
  - TP’s Transmission Customers’ projected Point-to-Point service needs
Local Transmission Plan Timing

- Two-year study cycle
- Twenty-year planning horizon
## Local Transmission Planning Cycle

### Biennial Planning Cycle and Schedule

<table>
<thead>
<tr>
<th>Months</th>
<th>Quarter</th>
<th>Activity</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>JAN-MAR</td>
<td>Qtr 1</td>
<td>Information Gathering</td>
<td>Receive and Prioritize Requests</td>
</tr>
<tr>
<td>APR-JUN</td>
<td>Qtr 2</td>
<td>Study Plan and Assumptions</td>
<td>Study</td>
</tr>
<tr>
<td>JUL-SEP</td>
<td>Qtr 3</td>
<td>Draft Plan Analysis</td>
<td>Report/Review Results</td>
</tr>
<tr>
<td>OCT-DEC</td>
<td>Qtr 4</td>
<td></td>
<td></td>
</tr>
<tr>
<td>JAN-MAR</td>
<td>Qtr 5</td>
<td>Draft Study Results and Review</td>
<td>Receive and Prioritize Requests</td>
</tr>
<tr>
<td>APR-JUN</td>
<td>Qtr 6</td>
<td>Economic Studies and Cost Allocation Process</td>
<td>Study</td>
</tr>
<tr>
<td>JUL-SEP</td>
<td>Qtr 7</td>
<td>Final Plan Report and Review</td>
<td>Report/Review Results</td>
</tr>
<tr>
<td>OCT-DEC</td>
<td>Qtr 8</td>
<td>Final Plan</td>
<td></td>
</tr>
</tbody>
</table>
Local Transmission Planning Inputs

- Load Forecasts
  - Native and Network Customers
- Resource Forecasts
  - IRP Preferred Portfolio
  - Network Resource Submittals
- Transmission Service Use Forecast
- Public Policy Requirements (RPS, Clean Power, etc)
Stakeholder Involvement

- Stakeholders may submit data to be evaluated as part of the Local Transmission Plan.
  - Alternative solutions
  - Public Policy

- Quarterly public meeting to review status and development of the Plan
Local Transmission Plan Output

• Study output identifies areas with projected performance violations

<table>
<thead>
<tr>
<th>Case</th>
<th>Number of Contingencies w/Violations*</th>
<th>Thermal Issues</th>
<th>Voltage Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>2023 Heavy Summer</td>
<td>4</td>
<td>4</td>
<td>1</td>
</tr>
<tr>
<td>2026 Heavy Summer</td>
<td>5</td>
<td>4</td>
<td>1</td>
</tr>
<tr>
<td>2028 NTTG Heavy Winter</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2038 Heavy Summer</td>
<td>46</td>
<td>40</td>
<td>14</td>
</tr>
</tbody>
</table>

* Some contingencies result in both a thermal issue and voltage issues.

• Determine system improvements needed for reliable operation

Improvement Plan
5 Year       10 Year       20 Year
Economic Studies

• Economic Study – Assessment to determine whether transmission upgrades can reduce the overall cost of reliably serving forecasted needs

• Requests accepted during Q1 or Q5 of the planning cycle
Regional Transmission Planning
FERC Order 1000
FERC Order 1000

• Requirements
  – Regional Planning Process
  – Cost Allocation
  – Interregional Coordination

• Open Access Transmission Tariff - Attachment K
Regional Transmission Planning Period

Regional Transmission Plan
Northern Tier Transmission Group (NTTG)

- Deseret G&T
- Idaho Power
- Northwestern Energy
- PacifiCorp
- Portland General Electric
- MATL LLP
Regional Transmission Planning Purpose

• Evaluates whether transmission needs within the regional footprint may be satisfied on a regional or interregional basis more efficiently or cost effectively than through the Local Planning Process

• Open planning process that provides valuable insight and information for all stakeholders

• Regional transmission planning process required by FERC
NTTG Planning Process Timeframe

- Two – year study cycle
- Ten – year planning horizon
NTTG Planning Process

Q1 Data Gathering and Project Submittal

Q2 Develop Study Plan

Q3/Q4 Prepare Draft Regional Trans. Plan

Q5 Stakeholder Review of Draft Plan

Q6 Updates to Biennial Study Plan

Q7 Draft Final Plan Review

Q8 Regional Trans. Plan Approval
NTTG Stakeholder Involvement

• End of Quarter Stakeholder Meetings
  – Status Reports of Progress and Receive Comments

• Stakeholders may also participate in public committee meetings
  – Steering Committee
  – Planning Committee
  – Cost Allocation Committee

• Stakeholder participation also through commenting
NTTG Planning Inputs

• Forecasted Loads and Resources

• Transmission Projects
  – Rolled up from Local Transmission Plans
  – Projects submitted for consideration by Project Sponsors, Stakeholders, or Merchant Developers

• Public Policy Requirements and Considerations
NTTG Study Method

- Production Cost Model run for year 10 utilizing Anchor Data Set
- Review of the results and selection of stressed hours for reliability analysis in power flow model
  - Round Trip Process
NTTG Study – Change Case Analysis

• Change case analysis

• Study multiple combination of submitted projects including Null (no added transmission case)
NTTG Study – Results

• Study result performance violations presented in heat maps
  – Maps show geographical problem performance areas for various change case combination of projects
Economic Evaluations

- Determine which plan with acceptable performance that meets regional needs is more efficient or cost effective.

- Metrics
  - Capital Related Costs
  - Energy Loss
  - Reserves
Cost Allocation

• Project Sponsors may request cost allocation consideration during project submission

• Project Qualification
  – Was proposed for cost allocation or was an unsponsored project
  – Selected in the Draft Regional Transmission Plan
  – Exceeds $20M

• Determine and allocate project costs
  – Costs allocated only if benefit/cost ratio is no less than 1.1
Regional Economic Study Requests

- Accepted During Q1 or Q5

- Up to two (2) Regional Economic Studies per cycle
WECC Role in Regional Planning

Model Building

- WECC is the Western Interconnection’s power flow and production cost model builder.
Interregional Coordination
Western Regions Coordinated Tariff

- Common provisions adopted by California Independent System Operator Corporation, ColumbiaGrid, NTTG Transmission Group, and WestConnect
  - Annual Interregional Information Exchange
  - Interregional Transmission Project Joint Evaluation Process
  - Interregional Cost Allocation Process
WECC Role in Interregional Planning

Model Building

• WECC is the Western Interconnection’s power flow and production cost model builder.
Markets

- Market expansions in the West are incremental market designs focused on leveraging CAISO’s existing market capabilities to deliver optimized dispatch savings to additional customers and helping to efficiently integrate renewable resources.

- Examples
  - Energy Imbalance Market (EIM)
  - Potential future Extended Day Ahead Market (EDAM)
EIM (and EDAM) Implementation

• NOT full markets like an Regional Transmission Organization (RTO)
  – Does not include consolidated Balancing Authority Area operations, integrated transmission planning, and transmission cost allocation
    • *intentionally designed* not to include these elements, as these have been some of the issues that have made market expansion very challenging to implement in the past
EIM (and EDAM) Benefits

• Produce granular Locational Marginal Prices (LMPs) and LMPs do include “congestion” as a price element

• Congestion shows where the transmission is constrained and could be contributing to less than optimal dispatch
  
  – Regional Planning Organizations outside of RTOs are not required by FERC to use LMP data in regional planning
  
  – However, the presence of this data from EIM may be useful in future planning processes
Planning Periods

- **Local Transmission Plan**
  - Operational Assessments
  - Near-term: 1 year
  - Long-term: 5 year, 10 year, 20 year
  - NERC Transmission Planning Assessments
  - 50 year, 100 year

- **Regional Transmission Plan**
  - 1 year

- **Integrated Resource Plan**
  - 5 year

- **Area Electric Plan**
  - 10 year

- **Near-term Long-term**
Planning Cycle Overlap

- Local Transmission Plan
  - 10 year
  - 5 year
  - 20 year

- Regional Transmission Plan
  - 2 years prior
  - Start of Planning Period
  - 1 year
  - 10 year

- Integrated Resource Plan
  - 2 years prior
  - Start of Planning Period
  - 1 year
  - 5 year
  - 10 year
WECC Study Development

Long-term Scenarios

Board Near-term Priorities

Stakeholder Comments

Study Program

Staff Resources
WECC Scenario Development

![Diagram showing the relationship between risk aversion, cost sensitivity, customer adoption of energy service options, and the direction of state and provincial energy policy. The diagram highlights the balance between market-based high degree of market freedom and policy-based low degree of market freedom, aiming to seek benefits and desire more options.]
WECC Phase 1 Assessments

• Changes to System Inertia with High Renewable Implementation
• Significant Electrification
• System Resilience Under Extreme Natural Disaster
• El Paso Natural Pipeline Disruption
• Water Availability Issues
• Reliability Impacts of Most Likely Year 10 Future
Scenarios

• Open Market, Restricted Choices
• Open Market, High Choice
• High Mandates, Restricted Choices
• High Mandates, High Choice
Scenarios

Open Market, Restricted Choices

High Mandates, Restricted Choices

Open Market, High Choice

High Mandates, High Choice

Customer Adoption of Energy Service Options

Direction of State & Provincial Energy Policy

Market Based High Degree of Market Freedom

Policy Based Low Degree of Market Freedom

Risk Averse Cost Sensitive

Seeking benefits Desire more options
State Engagement Updates

• NorthernGrid proposes the following state engagement tunings:
  – **Representation**: each state may have up to two representatives on the Enrolled Parties and States Committee; and
  – **Transparency**: each state may participate on the Cost Allocation Taskforce and will be represented on the Planning Committees;
  – **Decision-making**: consensus is the goal with supermajority vote when necessary
NorthernGrid Purpose

• Regional planning for the Pacific Northwest and Intermountain West region
• Single stakeholder forum for coordinated regional transmission planning
• Facilitate FERC Orders 890 and 1000 planning compliance for FERC jurisdictional companies
Committees and Responsibilities

**Member Committee**
Membership, Budget, Vendor Management

**Enrolled Parties and States Committee (EPSC)**
Stakeholders, Contribute to Scope, Comment on Plan

**Member Planning Committee**
Stakeholders, Coordination, Study Scope, Transmission Plan Approval

**Enrolled Parties Planning Committee**
Facilitate Compliance Determine eligibility for cost allocation

**Cost Allocation Task Force**
Facilitate Compliance Prequalification, Benefit and cost allocation
Committee Representatives

Member Committee
Representation
One per Member

Member Planning Committee
Representation
One per Member, EPSC Co-Chairs

Enrolled Parties Planning Committee
Representation
One per Enrolled Party
EPSC Co-Chairs

Enrolled Parties and States Committee (EPSC)
Representation
One per Enrolled Party, Up to two per State

Cost Allocation Task Force
Representation
One per Enrolled Party
One per State
Committee Leadership/Decisions

- **Member Committee**
  - Consensus
  - Supermajority

- **Enrolled Parties and States Committee**
  - Consensus
  - Supermajority of both classes

- **Jurisdictional and non-Jurisdictional Co-Chairs**
  - Member Planning Committee
    - Consensus
    - Supermajority

- **Enrolled Parties Chair**
  - Enrolled Parties Planning Committee
    - Consensus
    - Supermajority

- **Enrolled Parties and States Co-Chairs**
  - Cost Allocation Task Force
    - Consensus
    - Unanimous in both classes
EPSC Decision-Making

• Co-Chairs try to achieve consensus
  – Consensus does not mean unanimous; agreement must be reasonably met by the vast majority of the committee

• If no consensus:
  – Form Enrolled Parties and States classes
  – Each class must approve the proposal by a supermajority of three-quarters (75%)
    • If only one class approves, then an advisory minority report provided to the Planning Committee
Cost Allocation Decisions

• Unanimous agreement required for decisions pertaining to a FERC Order 1000 cost allocation
Planning Committee Decisions

• Co-Chairs try to achieve consensus
  – Consensus does not mean unanimous; agreement must be reasonably met by the vast majority of the committee

• If no consensus:
  – Each NorthernGrid representative has a vote
  – The Co-chairs of the Enrolled Parties and States Committee have one vote each
    • Co-chairs must represent the positions developed by the Enrolled Parties and States Committee
  – Approval requires 75% supermajority
Planning Process Overview

Planning Process
Regional Solutions to Member needs

Solutions to Enrolled Party needs

Order 1000 Cost Allocation
Are solutions more efficient or cost effective? Identify Benefits

Order 1000 Cost Allocation to Beneficiaries

One Regional Plan
Specifically identify regional solutions to the Enrolled Party needs and Cost Allocations, if any

Public Power Local Plan

Enrolled Party Local Plan

Project Cost Allocation Request
Local Plan Project

Planning Process
Regional Solutions to Member needs

Public Power Local Plan

Enrolled Party Local Plan

One Regional Plan
Specifically identify regional solutions to the Enrolled Party needs
Project Requesting Cost Allocation

Planning Process
Regional Solutions to Member needs

Solutions to Enrolled Party needs

Order 1000 Cost Allocation
Are solutions more efficient or cost effective?
Identify Benefits

Order 1000 Cost Allocation to Beneficiaries

One Regional Plan
Specifically identify regional solutions to the Enrolled Party needs and Cost Allocation Results, if any

Project requesting Cost Allocation
Committee Processing

- Study Scope
- Comments on the Plan
- Projects Seeking Cost Allocation
Contributions to Study Scope

Develop Contributions

Enrolled Parties and States Committee

Member Planning Committee

Consensus?

Y

Scope Element?

Include Contribution?

Regional

Y

Final Study Scope

Enrolled Party

Y

Unapproved Contribution Minority Report

N

Both Class Approval?

N

Enrolled Parties, States, vote

N

Draft Study Scope

Regional Enrolled Party
Comment on Regional Plan

- Develop Comments
- Enrolled Parties and States Committee
  - Consensus?
    - Y: Plan Element?
      - Y: Unapproved Comment Minority Report
      - N: Enrolled Party
    - N: Enrolled Parties, States, vote
  - N: Both Class Approval?
    - Y: Enrolled Party
    - N: Regional

- Member Planning Committee
  - Draft Regional Transmission Plan
  - Final Regional Transmission Plan
  - Include Comment?
    - Y: Enrolled Party
    - N: Regional
Cost Allocation Request Process

1. Draft Regional Transmission Plan

2. Is a project seeking cost allocation included?
   - Yes: Determine Beneficiaries and Benefits
   - No: No Cost Allocation

3. Determine Beneficiaries and Benefits

4. 125% Benefit to Cost Ratio?
   - Yes: Allocate Costs to Beneficiaries
   - No: No Cost Allocation

5. Allocate Costs to Beneficiaries

6. Unanimous
   - Yes: Include Project and Cost Allocation in the Final Plan
   - No: No Cost Allocation

7. Member Planning Committee

8. Member Planning Committee

9. Enrolled Parties Planning Committee

10. Member Planning Committee

11. Enrolled Parties Planning Committee

12. Member Planning Committee

13. Unanimous

14. Include Project and Cost Allocation in the Final Plan