



N T A C  
NW Transmission Assessment Committee

**PRELIMINARY AGENDA**  
**NW TRANSMISSION ASSESSMENT COMMITTEE (NTAC)**  
**March 13, 2007 – Portland, OR**  
**9:30 AM-3:30 PM – NWPP Offices, Portland, Oregon**

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1. **Introductions, Arrangements, and Agenda Changes** Chris Reese, PSE, Chair
2. **Meeting Notes – January 26, 2007** Dana Reedy, NWPP
3. **NTAC Sub-Regional Study Efforts**
  - a. **Mid-Columbia Transmission Planning Study Group** Eric Heredia
4. **Northwest Wind Integration Action Plan –Draft Transmission Recommendations**
  - a. **McNary-John Day Corridor** BPA
  - b. **I-5 Corridor** BPA
  - c. **Cross Cascades** John Phillips
  - d. **Montana (West Bound)-I5 Corridor Wind Oriented Studies** Chris Reese
6. **Projects Undergoing Regional Review - Updates**
  - a. **Northern Lights Proposal** Bill Hosie
  - b. **British Columbia to Northern California transmission project** Sherman Chen
  - c. **Sea Breeze Proposal – Juan de Fuca Cable Project** John Thompson
7. **Consolidated NTAC Regional Transmission Plans & Information** All
  - a. **List of Annual Progress Reports to WECC 2006** Chris Reese
  - b. **RANTS** Marv Landauer
  - c. **Regional Plan Template**
8. **FERC Order 890** Marv Landauer
9. **TEPPC/TAS Report**
  - a. **Model Work Group** Gordon Dobson-Mack
  - b. **Studies Work Group** Marv Landauer
  - c. **Historical Work Group** Chris Reese

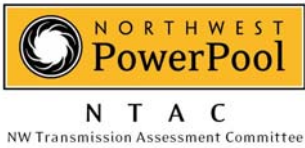
**10. Development of Future Work Efforts**

All

- a. PSASG (Canada-NW transfers)
- b. Wanapum-Avista 230 kV line
- c. LSE transformation studies Tacoma City and Snohomish

John Philips

**11. Next Meeting, Location**



*Northwest Transmission Assessment Committee Meeting  
March 13, 2007 – Portland, OR*

*Attendance List*

	<i>Name</i>	<i>Company</i>	<i>Phone Number</i>	<i>Email</i>
1	Chris Reese	PSE	425. 462.3055	<a href="mailto:chris.reese@pse.com">chris.reese@pse.com</a>
2	Mike Kriepe	BPA	360-418-8824	<a href="mailto:mjkreipe@bpa.gov">mjkreipe@bpa.gov</a>
3	Stephanie Lu	PSE	425-456-2582	<a href="mailto:stephanie.lu@pse.com">stephanie.lu@pse.com</a>
4	John Phillips	PSE	425-462-3579	<a href="mailto:john.phillips@pse.com">john.phillips@pse.com</a>
5	Jim Thornton	Ecology & Environment	530-248-5600	<a href="mailto:jthornton@ene.com">jthornton@ene.com</a>
6	Francis Tong	TPWR	253-502-8262	<a href="mailto:ftong@cityoftacoma.org">ftong@cityoftacoma.org</a>
7	Philip Augustin	PGE-T	503-464-7783	<a href="mailto:philip.augustin@pgn.com">philip.augustin@pgn.com</a>
8	Darrel VanCoevering	EnTranTelc	360. 546-2899	<a href="mailto:dgv@xprrt.net">dgv@xprrt.net</a>
9	Monte Meredith	TANC	208. 665-7990	<a href="mailto:mmeredith@navigantconsulting.com">mmeredith@navigantconsulting.com</a>
10	Adam Bless	OR Dept of Energy	503-378-8692	<a href="mailto:adam.bless@state.or.us">adam.bless@state.or.us</a>
11	Roger Hamilton	West Wind Wires	541-686-4839	<a href="mailto:hamilton.roger@comcast.net">hamilton.roger@comcast.net</a>
12	Brent Hendrickson	New Energy Assoc.	770-779-2851	<a href="mailto:bhendrickson@newenergyassoc.com">bhendrickson@newenergyassoc.com</a>
13	Eric Heredia	BPA T	360. 481-8441	<a href="mailto:emheredia@bpa.gov">emheredia@bpa.gov</a>
14	Rebecca Berdahl	BPA P	503-230-4502	<a href="mailto:rmberdahl@bpa.gov">rmberdahl@bpa.gov</a>
15	Jeff Miller	PAC	503. 813-5067	<a href="mailto:jeffrey.miller@pacificorp.com">jeffrey.miller@pacificorp.com</a>
16	Jamie Austin	PAC	503-813-5396	<a href="mailto:jamie.austin@pacificorp.com">jamie.austin@pacificorp.com</a>
17	Stefan Brown	OR PUC	503-373-7946	<a href="mailto:stefan.brown@state.or.us">stefan.brown@state.or.us</a>
18	E. John Tompkins	SBP-RTS	860-680-6667	<a href="mailto:ejt@trmc.com">ejt@trmc.com</a>
19	Chad Bowman	CHPD	509-661-4605	<a href="mailto:chadt@chelanpud.org">chadt@chelanpud.org</a>
20	Jim Eden	PGE-PS	503-464-7031	<a href="mailto:jim.eden@pgn.com">jim.eden@pgn.com</a>



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	<i>Name</i>	<i>Company</i>	<i>Phone Number</i>	<i>Email</i>
21	Bill Hosie	Northern Lights - TC	403-920-7338	<a href="mailto:bill_hosie@transcanada.com">bill_hosie@transcanada.com</a>
22	Dana Reedy	NWPP	503-445-1082	<a href="mailto:dana@nwpp.org">dana@nwpp.org</a>
23	Kip Sikes	IPC	208-388-2459	<a href="mailto:dsikes@idahopower.com">dsikes@idahopower.com</a>
24	Scott Waples	Avista	509-495-4462	<a href="mailto:scott.waples@avistacorp.com">scott.waples@avistacorp.com</a>
25	Marv Landauer	BPA	503-230-4105	<a href="mailto:mjlandauer@bpa.gov">mjlandauer@bpa.gov</a>
26	Paul Arnold	Col Grid	360-260-3214	<a href="mailto:pfavancouver@comcast.net">pfavancouver@comcast.net</a>
27				
28	<i>Phone/Webex:</i>			
29	Elroy Switlishoff	Columbia Power Corp.		
30	Bill Pascoe			
31	Kurt Conger			
32	Perry Cole	Trans-Elect		
33	Gordon Dobson-Mack	Powerex		
34	Ellen Feng	Powerex		
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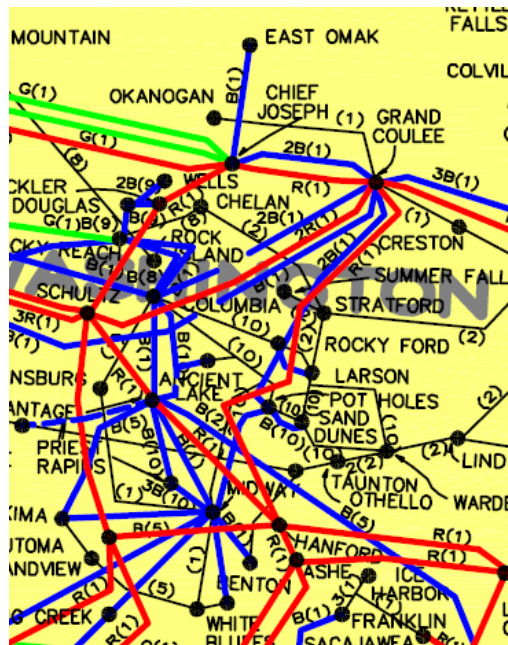
## NTAC Update

Mid Columbia Study expected to be completed by April. May need 50 mile Columbia-Wautoma 230 kV line along with several 115 kV upgrades on the parallel systems

Completed the South King County study – A 230 kV line rated at 1500 MVA will be constructed by 2008.

Several projects in the NTAC neighborhood are in WECC Regional Planning Process

- Northern Lights Project: Alberta-Celilo DC line
- Seabreeze Project: Submarine cable from Victoria to Port Angeles
- BC-Northern California



## Mid-Columbia Study

Multiple Users

Multiple Transmission Owners

Changing Generation Patterns

Changing Loads

Multiple lines at risk for Overloads

Used with Permission from Jay

## **Mid-Columbia Area Study**

### **Transmission Providers**

Avista, Bonneville Power Administration, Chelan PUD, Douglas PUD, Grant PUD, Pacific Power, Puget Sound Energy

### **Stakeholders**

Affiliated Merchants, Mid-C Power Purchasers, Renewable Resource Advocates, Regulators

### **Generation Resources**

Grand Coulee, Chief Jo, Well, Rocky Reach, Rock Island, Wanapum, Priest Rapids, and Wild Horse

Total Generation 15,000 MW

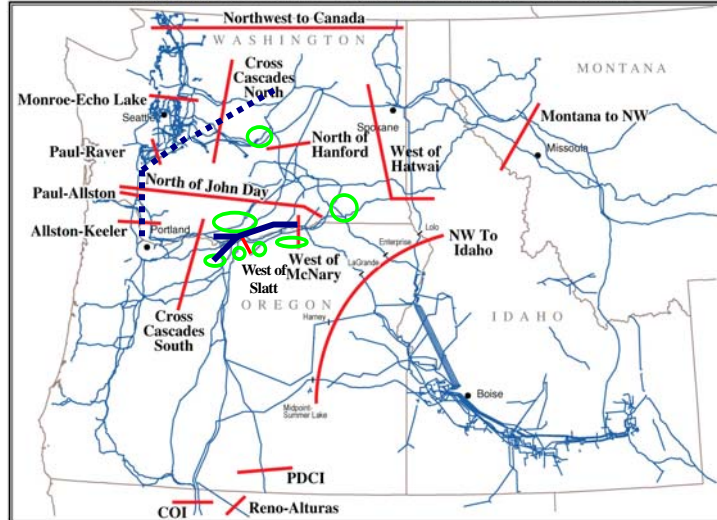
### **Transmission Requirements for Integrating 6,000 MW of Wind**

While the existing network appears capable of supplying long-term firm transmission capacity for the expected near-term (through 2009) demand for new wind power it is unlikely to be capable of accommodating further wind power development if the conventional practice of serving new generating capacity with firm transmission is continued.

Need to develop Plans of Service for:

- West of McNary: (Two phases) McNary-Big Eddy 500 kV Line Total Cost:  
Phase 1: \$420 M, Phase 2: \$200 M
- I-5 Corridor: Paul Troutdale 500 kV Line - \$480 M
- North Cross Cascades - \$ 1 Billion

### Conceptual Transmission Plans -Washington/Oregon



The Northwest Transmission Assessment Committee (NTAC) should propose a formal technical transmission planning methodology that seeks a balance between the cost of transmission capacity and the value of delivered wind energy.

Columbia Grid and the Northern Tier Transmission Group, together with NTAC, should begin applying the NTAC transmission planning methodology to regional transmission planning.

BPA and other Northwest parties should explore ways to make more efficient use of existing transmission infrastructure, such as conditional firm transmission service and redispatch. BPA should complete Plans of Service and review the business cases for the proposed West of McNary, I-5 Corridor and North Cross-Cascades transmission reinforcements.

BPA should develop a general model for financing market-drive transmission improvements, using the proposed West of McNary project as a prototype. NTAC should identify and evaluate approaches to delivering wind energy from Montana and other isolated wind resource areas.

# Cross-Cascade Study Update

John Phillips, PSE

## Background

- Path has historically been limited by voltage collapse limits in the Puget Sound region
- Limits are highly dependant on generation levels in the Puget Sound region
- Renewable mandates may result in Westside thermal generation being replaced with eastern Washington resources
  - PSE response could call for 1200 MW of east side wind generation, with proportional amounts from the neighboring utilities
- Study investigates several options to increase the capacity on this path

## Options

- Construct a new Chief Joe-Monroe 500 kV line
- Conversion of the Rocky Reach-Maple Valley 345kV line to a single 500kV line
- 50% series compensation of the Chief Joe-Monroe 500kV line, and Schultz-Raver #3&4 500 kV lines
- Conversion of the PSE's cross-Cascade 115kV line along I-90 to a single 230kV line
- Conversion of the Coulee-Olympia 287kV line to a single 500kV line
- Conversion of Rocky Reach-White River 230 kV line to 500 kV
- Construct Coulee-Vassau Lake with new Nicola-Meridian 500 kV line

## Methodology

- 2014 Heavey and Extra Heavy Winter cases
- Two generation scenarios
  - All Western Washington generation on at 90% of pmax
  - 60% of Western Washington generation on with thermal reduced and wind increased
- A QV analysis will be done for critical outages and for 500kV buses at Custer, Monroe, Echo Lake, Raver
- To determine possible impacts to other paths, PTDF values will be determined for each option using a Coulee-Malin source-sink for West of Cascades-North and South, Monroe-Echo Lake, Raver-Paul, South of Allston, and North of Hanford.

## Critical Contingencies

- Historically critical contingencies have been the following:
  - N-1: Chief Joe-Monroe 500kV line
  - N-2: Double Circuit Schultz-Raver #1 and Schultz-Echo Lake #1 500kV lines

## Activities

- Study Plan Drafted
- BPA (James Randall) and PSE (John Phillips) have begun QV runs using Power World

## **Proposed East of the Rockies Wind Resources to Washington/Oregon Loads Study**

There has been continual interest in determining the transmission options that could be used to integrate a large ( 1500-3000 MW) amount of wind resources located east of the Rocky Mountains with the intent to serve loads located in Washington/Oregon . This study plan proposes mirror the type of work performed in the Canada-Northwest-California study coupled with an updated RMATs-type study. The updated RMATs-type would use a production cost scenario that roughly models the western NWPP LSE's Integrated Resource Plans with a few of the transmission options that would be tested with a physical study that use power flow and stability analysis.

The physical studies could partition a transmission study into three components: a subregional resource integration component-east of the Rockies, a transfer path component from the eastern resources to the eastern Washington/Oregon transmission system, and a subregional load delivery component through Washington/Oregon load Delivery requirements. The objective is to give a ballpark accuracy estimates for both the MW integration capability and costs for wind generation acquisition. The delivery of the wind resources to loads outside of Washington and Oregon could be addressed in NTTG forum.

### **Resource Identification**

The suggested approach would be to assign generation to 230 and 500 kV buses.

1. Montana Resources – Up to 2000 MW
  - North Central Montana-assigned to 230 kV or new 500 kV buses
  - North East Montana-assigned to 230 kV or new 500 kV buses
  - Along Colstrip-Garrison 500 kV System-assigned to whatever buses
2. Wyoming Resources – Up to 2000 MW
  - Central Wyoming-assigned to 230 kV or new 345 kV buses
  - Eastern Wyoming- assigned to whatever kV buses

### **Conceptual Ideas**

- 1-13 Transmission Options-see diagram

### **Challenges**

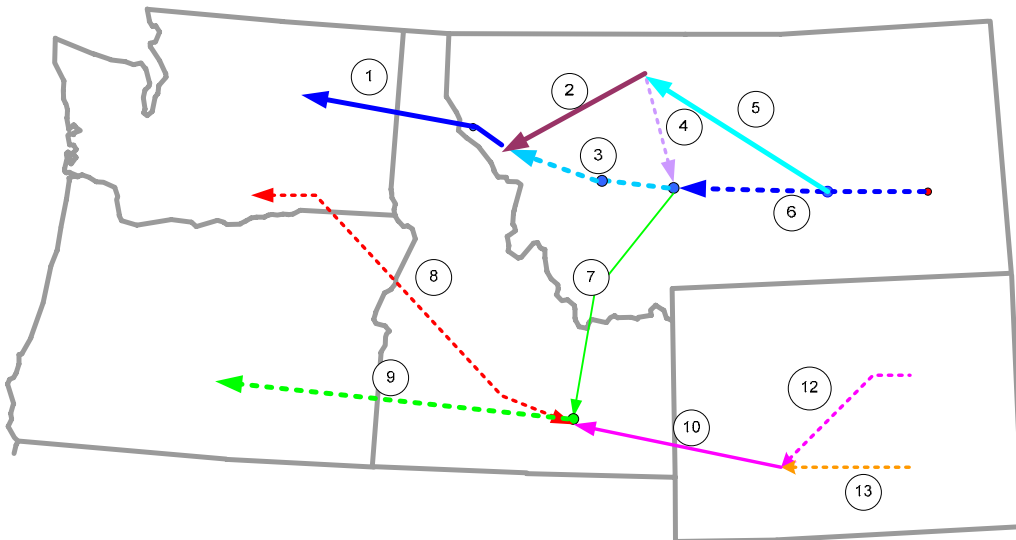
Do the options physically work, at what risk, and at what cost

## Methodologies

- Use existing information were available
- Power flow analysis of transmission options
  1. simultaneous transmission capacity performance increase (no derate of other rated paths during similar operating conditions)
  2. Other
- Measures of system performance
  1. Production Cost assessment
  2. Conditional firm assessment-Historical Use (and related views) and poweflow analysis
  3. Full year round capacity

## Deliverables

### Cost and Performance of Options



## **Regional Plan Project Template**

### ***For large projects, >200-kV, 300 MW***

- Project Name
- Short Project Description
- Sponsor
- Commitment Level
- Energization Date
- Geographic Location (need consistent method: State/province, city, area {ie, Puget Sound}, geographic {ie south central Washington}, location map)
- Cost of Project
- Project Need/Driver
- Project One-Line
- More Detailed Project Description
- Possible alternatives
- Required construction outages
- Two pages maximum

### ***For small projects, 100-kV to 200-kV***

- Project name/description
- Voltage
- Energization
- Location
- Sponsor
- Commitment level

mjl 11-30-04



# FERC Order 890 Planning Requirements

NTAC Meeting  
March 13, 2007



## **FERC Order 890 – Planning**

Commission concluded that TSPs have a disincentive to remedy increasing congestion on a non-discriminatory basis

1. TSPs must participate in coordinated, open and transparent planning process at both a local and regional level
2. Process must meet nine planning principles
3. FERC will allow regional differences



## 9 Planning Principles

### 1. Coordination

- Allow for reasonable and meaningful opportunity to meet

### 2. Openness

- Overall development of Tx plan and planning process must be open subject to CEII and confidentiality

### 3. Transparency

- Must disclose to all customers/stakeholders the basic criteria, assumptions, methodology and data that underlie the Tx plans, especially for native load to assure non-discrimination

### 4. Information Exchange

- Both network and point to point customers must provide information equivalent to that needed for native load planning both in substance and timing

3



## 9 Planning Principles (cont)

### 5. Comparability

- TSP must develop its plan that meets its service requests and otherwise similarly situated customers comparably

### 6. Dispute Resolution

- TSPs must develop Dispute Resolution Process

### 7. Regional Participation

- Must coordinate with interconnected systems outside TSPs control area to share system plans to ensure simultaneous feasibility, planned with consistent assumptions and data, and to identify enhancements to relieve congestion or integrate new resources

4



## 9 Planning Principles (cont)

### 8. Economic Planning Studies

- Planning must encompass projects to relieve congestion and integrate new resources in addition to reliability planning,
- Customers/stakeholders to choose which studies are of most value (e.g. 5 to 10 studies per year) but they must also provide appropriate information – specific service requests not needed
- Regional studies needed (prod/cost) in addition to specific local upgrades
- No requirement to build

5



## 9 Planning Principles (cont)

### 9. Cost Allocation for New Projects- NEW!!

- TSPs and stakeholders to develop own procedures that fits their experience and needs
- Cost Allocation is for projects not already covered under a single tariffs - such as regional projects
- No specific cost allocation method is proposed (“is not a matter for the slide-rule”)
  - Must fairly assign costs among those that cause or benefit
  - Must provide adequate incentive to build
  - Must be supported by states and participants
- Encourages regional solutions for free-rider problem
- Should be proactive rather than on a case-by case basis

6



## Order 890 – Planning

Rule encourages but does not require:

- Independent third party to lead planning process.
- State regulator participation
- Open season processes

Rule allows for recovery of planning costs

7



## Order 890 – Planning Timetable

- Strawman for compliance due 75 days after Order
- FERC is planning Technical Conferences 90-120 days after Order
- Revised Attachment K due 210 days after Order
- Order has not been posted on Federal Register as of 7 March (issued 16 Feb).

8

**V.B. Coordinated, Open Transmission Planning**

**210 days from FR**

**Draft and file Attachment K.** Each public utility Transmission Provider is required to submit a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in this Final Rule. In the alternative, a Transmission Provider (including an RTO or an ISO, as discussed below), may make a compliance filing in this proceeding describing its existing coordinated and regional planning process, including the appropriate language in its tariff, and show that this existing process is consistent with or superior to the requirements in this Final Rule.

437, 442, 602

This new attachment must therefore include:

- a) the process for consulting with customers and neighboring Transmission Providers;
- b) the notice procedures and anticipated frequency of meetings or planning-related communications;
- c) a written description of the methodology, criteria, and processes used to develop transmission plans;
- d) the method of disclosure of transmission plans and related studies and the criteria, assumptions and data underlying those plans and studies;
- e) the obligations of and methods for customers to submit data to the Transmission Provider;
- f) the dispute resolution process;
- g) the Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources; and
- h) the relevant cost allocation procedures or principles.

(More specific compliance requirements discussed below)

75 days from FR	<b>Draft and file a strawman planning procedure.</b> Each Transmission Provider should post a “strawman” proposal for compliance with each of the planning principles adopted in the Final Rule, including a specification of the broader region in which it will conduct coordinated regional planning. This strawman may be posted on the Transmission Provider's OASIS, or its website if it does not have its own OASIS ( <u>e.g.</u> , in the case of a transmission owning member of an RTO or ISO that does not have its own OATT).	443
210 days from FR	<b>Develop mechanisms to address confidentiality of planning-related information.</b> In conjunction with open planning meetings, Transmission providers, in consultation with affected parties, must develop mechanisms, such as confidentiality agreements and password-protected access to information, in order to manage confidentiality and CEII concerns.	460
210 days from FR	<b>Put transmission planning methodology in writing and disclose data.</b> The Commission will require Transmission Providers to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie their transmission system plans. In addition, Transmission Providers will be required to reduce to writing and make available the basic methodology, criteria, and processes they use to develop their transmission plans, including how they treat retail native loads, in order to ensure that standards are consistently applied.	471
210 days from FR	<b>Implement mechanism to make upgrade status available.</b> The Commission requires that Transmission Providers make available information regarding the status of upgrades identified in their transmission plans in addition to the underlying plans and related studies.	472
210 days from FR	<b>Develop guidelines for planning submittals.</b> The Commission requires Transmission Providers, in consultation with their customers and other stakeholders, to develop guidelines and a schedule for the submittal of information. The information must be made available at regular intervals to be identified in advance.	486

210 days from FR	<b>Develop ADR for planning disputes.</b> The Commission adopts the NOPR's proposal to require Transmission Providers to develop a dispute resolution process to manage disputes that arise from the Final Rule's planning process. An existing dispute resolution process may be utilized, but those seeking to rely on an existing dispute resolution process must specifically address how its procedures will be used to address planning disputes.	501
210 days from FR	<b>Coordinate planning with interconnected systems.</b> In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each Transmission Provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources.	523
210 days from FR	<b>Develop method for requesting economic upgrade studies.</b> Customers must be allowed to request that economic upgrades be studied. Transmission providers must coordinate on these issues as necessary in sub-regional or regional planning processes. To the extent the NERC processes are not considered appropriate for such economic issues, individual regions or sub-regions may develop alternative processes. Stakeholders be given the right to request a defined number of high priority studies annually ( <u>e.g.</u> , five to ten studies) to address congestion and/or the integration of new resources or loads.	528, 547
210 days from FR	<b>Develop a planning method that considers reliability and economics.</b> The transmission planning process under the <i>pro forma</i> OATT must consider both reliability and economic considerations. The purpose of this principle is to ensure that the latter is considered adequately in the transmission planning process.	542
210 days from FR	<b>Develop a means to allow for clustering of economic studies and posting of such studies.</b> Additionally, FERC directs Transmission Providers to develop a means to allow the Transmission Provider and stakeholders to cluster or batch requests for economic planning studies so that the Transmission Provider may perform the studies in the most efficient manner. FERC requires the requests for economic planning studies, as well as the responses to the requests, be posted on the Transmission Provider's OASIS or web site, subject to confidentiality requirements.	546

210 days from FR	<b>Define the information sharing requirements for planning.</b> FERC directs Transmission Providers to clearly define the information sharing obligations placed on customers in the planning attachment to their <i>pro forma</i> OATT.	550
210 days from FR	<b>Identify the type of projects to be covered by cost allocation principle that is to be developed.</b> The cost allocation proposal should identify the types of new projects that are not covered under existing cost allocation rules and, therefore, would be affected by a new, proposed cost allocation principle. Transmission providers should also consider whether mechanisms for regional cost recovery may be appropriate, such as through agreements (formal or informal) to incur and allocate costs jointly.	558
210 days from FR	<b>Coordinate planning with state regulators.</b> Planning must be coordinated with relevant state regulators (including city councils, local siting boards, and other agencies) that wish to participate in the Transmission Provider's planning process.	574
210 days from FR	<b>Develop cost recovery proposal.</b> FERC directs Transmission Providers to work with other participants in the planning process to develop their cost recovery proposals in order to determine whether all relevant parties, including state agencies, have the ability to recover the costs of participating in the planning process.	586
<b>V.C. Transmission Pricing</b>		
<b>2. Energy and Generation Imbalances</b>		
60 days from FR	<b>Implement new pricing mechanisms for energy imbalance service (and for new, generation imbalance service).</b> Transmission providers must price imbalances in accordance with new pro forma OATT. These provisions must adhere to three principles: (1) the charges must be based on incremental cost or some multiple thereof; (2) the charges must provide an incentive for accurate scheduling, such as by increasing the percentage of the adder above (and below) incremental cost as the deviations become larger; and (3) the provisions must account for the special circumstances presented by intermittent generators and their limited ability to precisely forecast or control generation levels, such as waiving the more punitive adders associated with higher deviations.	663-722

<b>60 days from FR or later (Optional)</b>	<b>File rate schedule, if desired, for demand charges.</b> If the Transmission Provider elects to have separate demand charges assigned to customers for the purpose of recovering the cost of holding additional reserves for meeting imbalances, the Transmission Provider should file a rate schedule and demonstrate that these charges do not allow for double recovery of such costs.	690
<b>60 days from FR</b>	<b>Provide generation imbalance service (and implement pricing mechanism).</b> All Transmission Providers must submit compliance filings (OATTs) containing Generation Imbalance Service.	670
<b>60 days from FR</b>	<b>Develop crediting mechanism for imbalance penalty revenues.</b> Transmission providers are required to develop a mechanism for crediting penalty revenues in their compliance filing to all non-offending transmission customers (including affiliated transmission customers) and the Transmission Provider on behalf of its own customers.	727
<b>4. Capacity Reassignment</b>		
<b>After NAESB acts</b>	<b>Post re-sales/assignments of transmission capacity.</b> All sales or assignments of transmission capacity will be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences. The transmission customer may either request that the Transmission Provider make the capacity available on its OASIS or the transmission customer may negotiate the terms of an assignment bilaterally. In either instance, however, the resulting sale or assignment must be posted by the Transmission Provider on its OASIS prior to the date the reassigned service commences. FERC requires Transmission Providers working through NAESB to develop appropriate OASIS functionality to allow such postings.	815 (18 CFR § 37.6(c)(5))
<b>60 days from FR</b>	<b>Sign service agreements with assignees.</b> Assignees of transmission capacity execute a service agreement with the Transmission Provider prior to the date on which the reassigned service commences.	816
<b>60 days from FR (but first EQR not due until 30 days after quarter ends)</b>	<b>Include capacity assignments on EQRs.</b> FERC requires Transmission Providers to aggregate and summarize in an electronic quarterly report the data contained in these service agreements, as a new product, "Capacity Reassignment." The Commission directs that this quarterly report be submitted electronically in spreadsheet format consistent with the electronic filing system used for Electric Quarterly Reports so that it is readily accessible to the Commission and the public.	817

<b>5. Operational Penalties</b>		
<b>60 days from FR or later (Optional)</b>	<b>Develop penalty rate for unreserved use.</b> A Transmission Provider that wants to charge unreserved use penalties must explicitly state the penalty rate in its tariff. (Existing penalties may have to be modified in accordance with guidance in Order 890.)	848
<b>1 year after effective date of Order 890</b>	<b>Make compliance filing and propose mechanism regarding distributing unreserved use and late study penalties.</b> The Commission requires the Transmission Provider to make an annual compliance filing and to propose in that filing a mechanism through which it will identify non-offending, transmission customers and a method by which it will distribute the unreserved use penalties revenue it receives to the identified transmission customers. The Transmission Provider must also indicate in its compliance filing how it will distribute late study penalties to unaffiliated transmission customers. A Transmission Provider will be required to distribute the entire amount it pays for completing service request studies on an untimely basis	861
<b>1 year after effective date of Order 890</b>	<b>Make annual penalty informational filing.</b> Transmission providers must provide in their annual informational filings: (1) a summary of penalty revenue credits by transmission customer, (2) total penalty revenues collected from affiliates, (3) total penalty revenues collected from non-affiliates, (4) a description of the costs incurred as a result of the offending behavior, and (5) a summary of the portion of the unreserved penalty revenue retained by the Transmission Provider.	864

**V.D. Non-Rate Terms and Conditions**

**1. Modifications to Long-Term Firm Point-to-Point Service**

**60 days after FR**

**Comply with new requirements on planning redispatch and conditional firm service (CFS).** If customers request study of planning redispatch, Transmission Providers have an obligation to seriously evaluate the provision of planning redispatch from their own resources and provide customers with information on the capabilities of other generators to provide planning redispatch. If planning redispatch is unavailable from the Transmission Provider's resources or inadequate to meet customers' needs, Transmission Providers have an independent obligation to offer conditional firm, if available, as part of the firm point-to-point service. the Transmission Provider shall, at the request of the customer and in the system impact study, identify (1) the transmission upgrades necessary to provide the service, and (2) the options for providing service during the period prior to completion of those transmission upgrades. Additionally, if upgrades cannot be completed prior to expiration of the requested service term, the Transmission Provider shall, at the request of the customer and in the system impact study, identify options for providing the service during the requested term. The options studied by the Transmission Provider must include planning redispatch and conditional firm options. The Transmission Provider, at its discretion, may study and offer a mix of planning redispatch and conditional firm options for a single service request.

914-915, 941, 946, 957, 981