

**ELECTRIC RELIABILITY COUNCIL OF TEXAS
2008 ANNUAL REPORT**

ERCOT QUICK FACTS

At a glance

Customers served: 22 million
 Area served: 85% of Texas load, 75% of Texas land
 Generating units: 566
 High-voltage transmission: 40,327 miles
 Installed capacity: 80,076 megawatts (MW)
 Net dependable capacity: 72,712 MW
 Reserve margin: 16.8%
 (minimum required 12.5%)
 Record peak demand: 62,339 MW (August 2006)
 Energy produced: 312 billion kilowatt-hours (2008)
 Market size: \$34 billion, based on 312,402 GWh market volume and average \$0.11/KWh rate
 Market participants: 828 active entities that generate, move, buy, sell or use electricity at wholesale level
 Wind generation: 8,000 MW – most in nation
 Demand response: 1,115 MW (equal to three major power plants) in load resource program

What do we do?

The Texas Legislature restructured the Texas electric market in 1999 by unbundling the investor-owned utilities and creating retail customer choice in those areas, and assigned ERCOT four primary responsibilities:

- System reliability – planning and operations
- Open access to transmission
- Retail switching process for customer choice – the only independent system operator with responsibilities as registration agent for retail transactions
- Wholesale market settlement for electricity production and delivery.

Other Organizational Functions

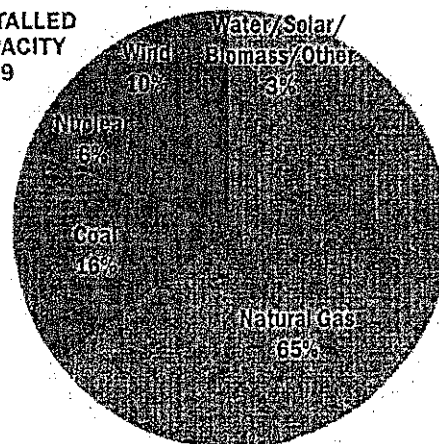
Wholesale market (bilateral): ~95% of market
 Balancing energy/ancillary services market: ~5%
 System planning coordination
 Renewable Energy Credits management (statewide)
 Market participant/stakeholder activity support

How are we doing?

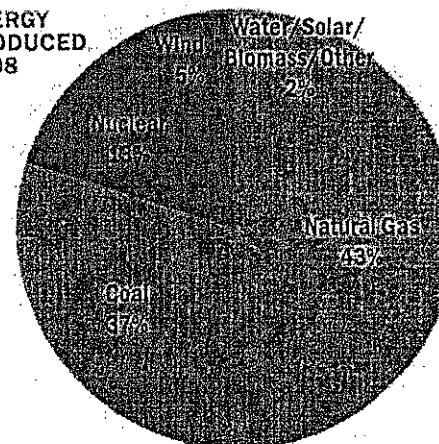
Transmission Investment

- 6,593 circuit miles of transmission improvements since 1999
- 2,888 circuit miles of transmission under study
- \$4.4 billion in transmission added since 1999
- \$3 billion under development in five-year plan
- \$4.93 billion under development to support 18,000 MW of new wind (CREZ Project)

INSTALLED CAPACITY 2009



ENERGY PRODUCED 2008



Generation Development

- 39,000 MW new generation added since 1996
- 9,000 MW generation committed for the future (with transmission contract and air permit)
- 97,000 MW of new generation requests under review, including ~ 48,000 MW wind, 12,300 MW nuclear, 24,000 MW natural gas, 7,500 MW coal, and 1,800 MW solar and biomass (April 2009)

Retail Service Switches to Competitive Retailers

47% of residential load (April 2009)
 77% of small commercial load (April 2009)

What's ahead?

Advanced metering project; estimated launch in November 2009.

Comprehensive nodal market implementation, anticipated launch in 2010, to include:

- Nodal locational marginal pricing for generation
- Congestion revenue rights
- Day-ahead energy and ancillary services co-optimized market
- Day-ahead and hourly reliability unit commitment.

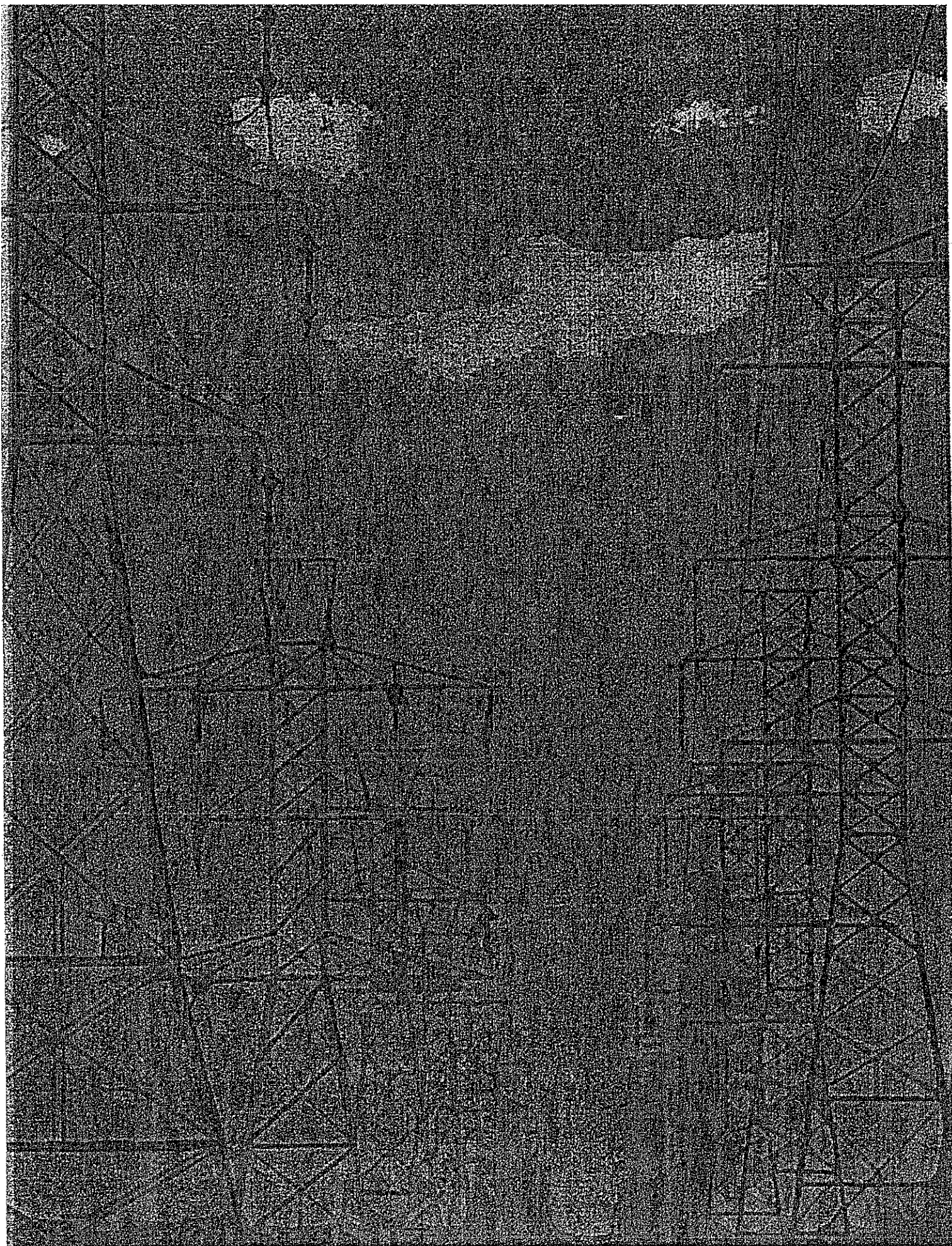
CONTENTS

From the Chair: Building a Grid for the Future	5
From the CEO: Meeting Challenges Each Step of the Way	6
Vision and Mission	7
Grid Operations: Ensuring Reliability Day-to-Day	8
Generation, Transmission Planning: Planning Reliability for the Future	10
Renewable Energy: ERCOT Leads the Way	12
Market Operations: Ensuring a Fair and Competitive Market	13
Nodal Market Implementation: Redesign on Track for 2010 Completion	14
Texas Nodal: At a Glance	15
ERCOT Members: 2008	16
Five-year Summary: Financial, Operating, Retail Transactions Data	18
ERCOT Governance	19



The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to approximately 22 million Texas customers – representing 85 percent of the state's electric load and 75 percent of the Texas land area. The ERCOT Region includes Houston, Dallas, Fort Worth, San Antonio, Austin, Corpus Christi, Abilene and the Rio Grande Valley. ERCOT does not include the El Paso area, the Texas Panhandle, Northeast Texas (Longview, Marshall and Texarkana), and Southeast Texas (Beaumont, Port Arthur, and the Woodlands).

Régie de l'énergie
DOSSIER: R-3661-2008
DÉPOSÉE EN AUDIENCE Phase 2
Date: 9/05/2011
Pièces n°: B.232





Jan Newton
Chair, ERCOT Board

FROM THE CHAIR

Building a Grid for the Future

I accepted the chairmanship of the Electric Reliability Council of Texas (ERCOT) Board of Directors in December 2008. It could not have been a more challenging time to take the reins, and yet I am very excited and optimistic about ERCOT's future.

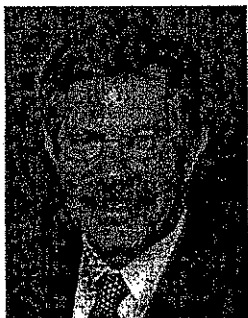
The issue looming ahead of us is the implementation of the nodal market. At its simplest level, the nodal structure will move ERCOT from four zones to 4,000 nodes, making it easier for ERCOT operators to identify and resolve congestion. A nodal market provides more granular pricing - sending better "market signals" to help industry investors identify exactly where new generation is needed and help ERCOT determine the best location for new transmission. These efficiencies are expected to yield lower costs for the wholesale market, and ultimately, for consumers.

But the nodal market redesign includes much more - it's a multi-layered engineering and business transformational program, involving hundreds of complex workflows and processes. Besides nodal locational marginal pricing for generation, the project will add a day-ahead energy and ancillary services co-optimized market, congestion revenue rights, and day-ahead and hourly reliability unit commitment. Other deliverables include a wind-forecasting service and enhanced load forecasting tools, information technology hardware, and infrastructure improvements which will help bring Texas' grid into the 21st century.

ERCOT has been a leader in integrating renewable generation, building transmission, and aggressively pursuing demand response programs. But we need a smart, agile electric grid to manage the increased demand, increased population, and increased market complexity that we are expecting in Texas. The nodal market design with its enhanced grid management tools will allow ERCOT to take advantage of new advances in renewable technologies, energy storage, plug-in vehicles, demand response, and efficiency programs while maintaining reliability.

On behalf of the ERCOT board, members and market participants, I want to thank Mark Armentrout for his outstanding leadership as chairman for the last three years. I hope to continue his excellent record and continue building on ERCOT's core strengths - maintaining reliability for the electric consumers in Texas, effectively managing the competitive electric markets in Texas, and serving as an expert planning resource for new and expanded energy resources in the state - none of which would be possible without the ERCOT employees. Our appreciation goes to them for their hard work and constant vigilance to build ERCOT's reputation as a world-class independent system operator.

Jan Newton
Chair, ERCOT Board of Directors



Bob Kahn
President and CEO

FROM THE CEO

Meeting Challenges Each Step of the Way

For the seventh year since ERCOT assumed management of the Texas electric grid, we successfully fulfilled our primary mission – maintaining the reliability of the grid – while handling numerous other responsibilities related to system planning, wholesale market settlement, retail switching, and running the day-to-day operations of the Texas electric market. As the ERCOT market matures and evolves, we continue to experience and meet new challenges.

The primary challenge we faced in 2008 was getting the Nodal Market Implementation Program back on track. A new project management office was created, along with tighter controls and new leadership. We developed a detailed, integrated schedule – painstakingly created over several months from the ground up. The new schedule is a comprehensive roadmap for getting to go-live that includes an “early warning system” to identify risks and problems before they become emergencies. I am confident that the nodal project is on track to launch by December 2010 – on schedule and on budget.

Leading the way with wind, transmission

We marked accomplishments in other areas, as well. Texas continues to make headlines as the top wind-producing state, and ERCOT is leading the way in reliably integrating increasing amounts of renewable generation. The Competitive Renewable Energy Zones (CREZ) initiative will expedite construction of \$5 billion in transmission lines to move 18,000 megawatts of renewable generation to the populous portions of the state.

In addition to the CREZ transmission, ERCOT is reviewing proposed transmission projects for the next five years totaling \$3 billion and expected to improve or add 2,888 circuit miles of transmission to the grid.

ERCOT continues to attract record-level interest from generation developers, as evidenced in the large amounts of proposals in the permitting or study phase, including more wind and nuclear announcements than any other state. ERCOT is currently reviewing almost 100,000 MW of generation requests, including close to 50,000 MW of wind projects.

We continue to focus on the need for increased fuel diversity. Reducing the ERCOT market's reliance on natural gas capacity would have positive implications for reliability and price stability.

We are also working closely with the Public Utility Commission and market participants on advanced metering issues. Advanced meters are key to a modern power grid and a way to reduce energy consumption through mass market demand response.

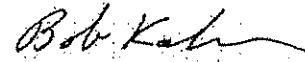
Strengthening leadership, compliance focus

We strengthened the leadership team with the creation of three new positions including a chief operating officer to direct system operations, system planning, market operations, and compliance; and a chief administrative officer, consolidating the human resources and organizational development with project management and strategic planning for greater efficiency. We also added a chief compliance officer to centralize the compliance functions across the organization and further strengthen our focus on compliance.

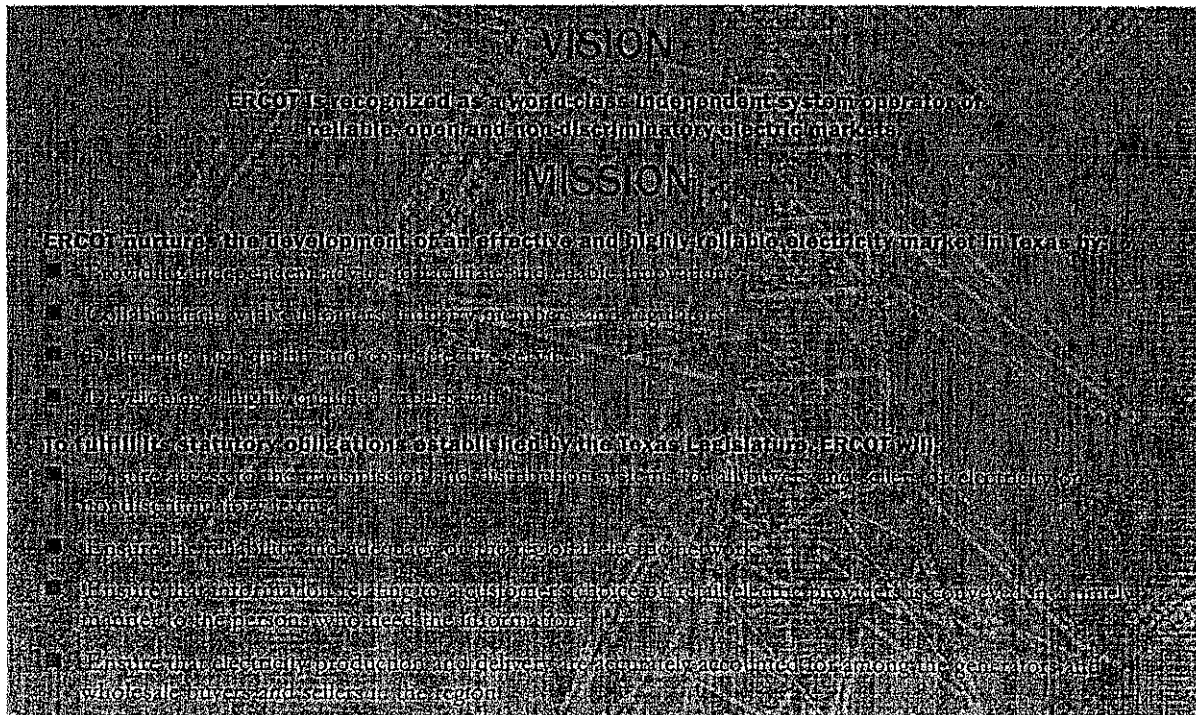
In other notable successes during the year, ERCOT:

- Received a coveted “unqualified” opinion with “no exceptions” on the 2008 Statement on Auditing Standards (SAS) 70 audit prepared by PricewaterhouseCoopers. PwC’s audit covered controls related to the market settlements process, the information technology infrastructure that supports the markets, and security. The unqualified audit with no exceptions affirms the reliability of the foundational processes performed and data provided by ERCOT staff for each market participant.
- Updated liquidity plans to maintain stability of the electricity markets and successfully negotiated debt capacity increases and favorable debt pricing in spite of unprecedented financial market turmoil.
- Received high marks in a biannual market participant survey for staff performance and data communications provided to the market. The survey results indicated that market participants feel ERCOT staff is performing exceedingly well regarding accomplishment of corporate objectives, with the highest marks recorded for employees’ industry expertise and attitude.

I would like to echo the findings of the market participant survey by praising the expertise and diligent attitudes of ERCOT employees. Every day of the year, it is the employees’ skills and dedication that keep us moving forward with our eyes on the ERCOT mission – to nurture development of an effective and highly reliable electricity market in Texas.



Bob Kahn
President and CEO



VISION

ERCOT is recognized as a world-class independent system operator of reliable, open and non-discriminatory electric markets.

MISSION

ERCOT nurtures the development of an effective and highly reliable electricity market in Texas by:

- Providing market participants the information and enablement systems.
- Collaborating with customers, industry members and regulators.
- Promoting high quality and competitive services.
- Developing highly qualified staff.

to fulfill its statutory obligation established by the Texas Legislature (ERCOT III):

- Ensure access to the transmission and distribution system to all buyers and sellers of electricity on non-discriminatory terms.
- Ensure the reliability and adequacy of the regional electric network.
- Ensure that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to the persons who need the information.
- Ensure that electricity production and delivery is accurately accounted for among the generators and wholesale buyers and sellers in the region.

GRID OPERATIONS

Ensuring Reliability Day-to-Day

Operators weather two hurricanes

ERCOT successfully fulfilled its primary responsibility to maintain reliability of the grid despite two hurricanes and several emergency events in 2008.

Hurricane Dolly made landfall as a Category 1 storm on July 23 at South Padre Island, with 85 mph winds. ERCOT operators managed significant transmission and generation outages in the southern portion of the ERCOT grid. Customer outages during the hurricane's aftermath exceeded 224,600 in the Rio Grande Valley area, and 28 high-voltage transmission lines were knocked out of service.

On September 13, Hurricane Ike hit Galveston as a Category 2 hurricane with winds of 110 mph, becoming the country's third most destructive hurricane as measured in property damage. More than 100 high-voltage transmission lines and 35 generation units were knocked out of service initially, affecting service to approximately 2.1 million customers in the ERCOT region. ERCOT's system operators quickly responded to the sudden and dramatic losses of electric load caused when the storm disabled electric lines and generating units, keeping the rest of the grid intact.

Load resources deployed twice for low frequency events

Twice during the year, ERCOT operators initiated emergency procedures to manage a sudden drop in frequency or operating reserves. The first event occurred on February 26 when a cold front moved through the state resulting in an unexpected drop in wind energy production after the front's passage at the same time that system load was increasing and several other power providers were falling below their scheduled energy production.

Faced with a drop in frequency, the operators moved directly to the second stage of emergency procedures which activated ERCOT's demand response program, Loads Acting as Resource (LAARs), adding approximately 1,100 MW of resources within a 10-minute period. LAARs are primarily large industrial and commercial users who are paid to curtail their electricity use as need-

ed for reliable grid operation. Other than the load resources, which were mostly restored within an hour and a half, no customers in the ERCOT region lost power due to the event. The interruptible load resources were also activated August 11 to assist in restoring the frequency following the loss of a 1,662 MW generating plant.

On June 18, ERCOT operators initiated emergency procedures when operating reserves dropped below the target minimum of 2,300 MW. The primary reason was hotter-than-forecasted temperatures in several areas of the region. Load was 2,100 MW higher than the day-ahead load forecast due to temperature predictions lower than actual. Operators brought on additional generation and cancelled the emergency procedures within two hours.

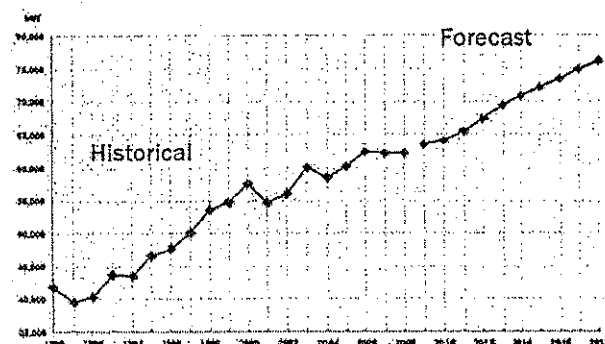
Total energy production up 1.7 percent

Energy consumed in the ERCOT region in 2008 totaled 312,401 gigawatts, a 1.7 percent increase over 2007. The month of June had the highest increase at 11.8 percent, followed by July with 11.3 percent and May with 9.6 percent.

Wind energy marked the largest percentage increase in energy generation, going from 2.9 percent of total energy in 2007 to 4.9 percent in 2008.

The peak demand for 2008 was 62,174 MW, recorded on Monday, August 4, for the 4-5 p.m. hour, representing

PEAK DEMANDS, 1990-2014



0.1 percent less than the 2007 peak of 62,188 MW and 0.3 percent less than the all-time peak of 62,339 MW (August 2006).

Also during 2008, system operations:

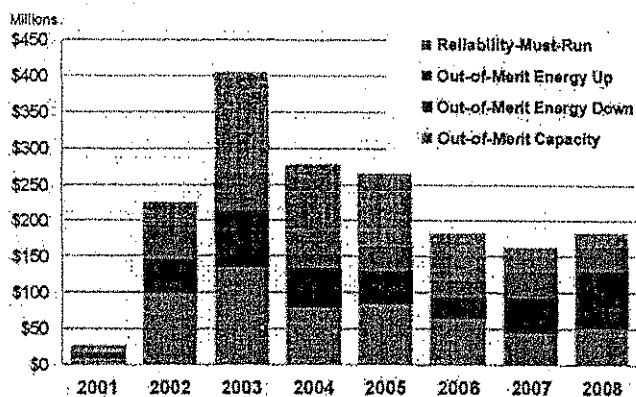
- Received an internal audit rating of 99.4 percent compliance with operating procedures, exceeding the goal of 98 percent;
- Received a finding of "No exceptions" from a North American Electric Reliability Corporation (NERC) Readiness Review in April;
- Implemented a new optimized selection method for black-start resources, resulting in a savings of \$1.6 million in the annual cost;
- Implemented a real-time commercially-significant-constraint limit calculator enabling ERCOT to maximize the transfer between congestion zones while maintaining reliability;
- Changed the ancillary service requirement methodology to accommodate the rapid increase in intermittent wind generation;
- Processed more than 35,000 planned transmission outage requests.

Board acts quickly to address congestion issues

Zonal congestion costs (between the four congestion zones) had been trending downward over the past few years, from \$146 million in 2001 to \$52 million in 2007, but costs in 2008 increased to \$360 million, primarily due to a combination of events, including transmission constraints, high fuel costs, and increased wind generation.

The ERCOT Board of Directors implemented emergency market rule changes in early summer to mitigate the high congestion costs. They approved a protocol revision that modified long-standing market rules – allowing the system operators to resolve a particular type of transmission congestion with more efficient local-

INTRAZONAL (LOCAL) CONGESTION COSTS



congestion management techniques, rather than zonal-congestion management. Under local-congestion management, ERCOT operations is able to deploy individual generation units that provide the greatest relief on a constraint rather than zonal generation portfolios.

In a second emergency meeting, the board approved a change imposing a cap on the market clearing price for energy which is produced through the bid stack, setting it at no more than the bid ceiling price.

Local congestion up slightly

Intra-zonal – or local – congestion costs were slightly higher in 2008 at \$184.2 million, compared to \$164.4 million in 2007. Local congestion costs have been trending downward since the 2003 high of \$405.1 million. Local congestion costs are highly dependent on local generation availability, limits of the transmission infrastructure, local area demand, and projected load growth.

Moving to the nodal market design will allow more efficient congestion management through improved dispatch efficiencies at the individual resource level every five minutes, rather than by portfolio every 15 minutes.

GENERATION, TRANSMISSION PLANNING

Planning Reliability for the Future

New generation improves outlook

Generation developers continue to show an interest in the ERCOT market as evidenced by 4,245 MW of new installed generation in 2008. In addition, more than 9,000 MW of committed future generation (with completed interconnection agreements and necessary air permits) and approximately 97,000 MW of proposed generation was under review at the end of April 2009.

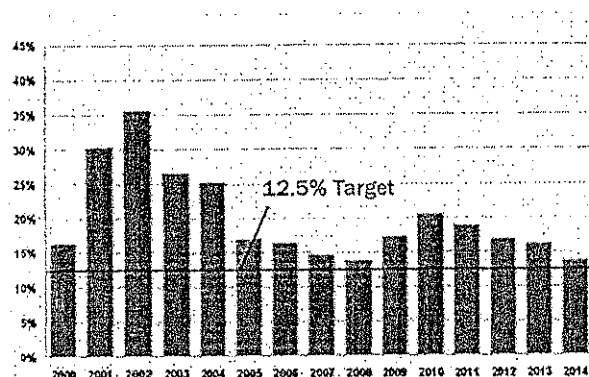
The reserve margin forecast improved in 2009 to 16.8 percent, well above the 12.5 percent minimum required. (Reserve margins are assessments based on best estimates of a snapshot in time; the assessments change as new generation is added and old generation is mothballed or decommissioned, and load forecasts change based on changing economic conditions and other factors.)

In 2008, new installed and committed generation included 5,040 MW from gas-fired units, 4,046 MW from coal, 5,040 MW from wind, and 145 MW from biomass.

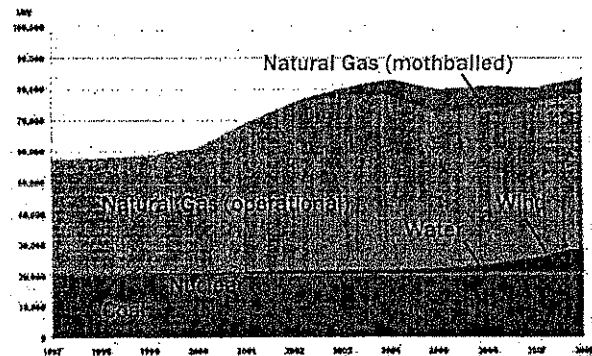
Generation that became operational in 2008 included:

- 80 MW, coal, J T Deely Upgrade, Bexar County
- 193 MW, gas, Laredo Peaking Power Plant, Webb County
- 275 MW, gas, Quail Run Energy Center 2, Ector County
- 275 MW, gas, Colorado Bend Energy Center 2, Wharton County

ERCOT RESERVE MARGINS, 2000-2014



GENERATION CAPACITY BY FUEL TYPE, 1997-2008



- 332 MW, gas, Victoria Power Station, Victoria County
- 3,220 MW, wind, at multiple locations.

Major generation committed for 2009 and beyond includes:

- 581 MW, coal, Sandow 5, Milam County
- 750 MW, coal, J K Spruce 2, Bexar County
- 925 MW, coal, Sandy Creek 1, McLennan County
- 1,710 MW, coal, Oak Grove SES, Robertson County
- 544 MW, gas, Cedar Bayou 4, Chambers County
- 255 MW, gas, Bosque Expansion, Bosque County
- 178 MW, gas, Winchester Power Park, Fayette County
- 244 MW, gas, South Houston Green Power, Galveston County
- 327 MW, gas, Nueces Bay 7 Repowering, Nueces County
- 200 MW, gas, Pearsall Expansion, Frio County
- 360 MW, gas, Barney Davis 2 Repowering, Nueces County
- 50 MW, gas, TECO Central Plant, Harris County
- 1,792 MW, gas, Cobisa-Greenville, Hunt County
- 2,702 MW, renewable (wind and biomass), at multiple locations.

A new consideration in last year's assessment was 143 MW of demand supplanted by energy efficiency

conservation efforts as reported to the Public Utility Commission by ERCOT member utilities, in compliance with Legislative House Bill 3693 (2007). Load decrease for 2009-2013 was estimated at 160 MW.

The forecasted growth rate for peak demand over the next five years is 2.2 percent, slightly higher than the forecasted growth rate of 1.9 percent in 2008.

Transmission Improvements total almost half a billion dollars

ERCOT's annual transmission planning report issued in December 2008 included \$3 billion in proposed projects for the next five years, expected to improve or add 2,888 circuit miles of transmission and more than 17,000 megavolt ampere (MVA) of autotransformer capacity to the grid.

The major planned transmission additions in the five-year plan include:

- Waller-Prairie View-Seaway-Macedonia line reconductor, 138 kV, 22 circuit miles, Coast area, operational 2010
- Robertson-Watson Chapel line rebuild, 138 kV, 21.6 circuit miles, East area, operational 2010
- Twin Oaks-Bell County SE line addition, 345 kV, 88 circuit miles, East - North Central area, operational 2011
- Oklaunion-Bowman line addition, 345 kV, 50 circuit miles, North area, operational 2012
- Hutto Switch-Salado Switch line addition and Switching Station, 345 kV, 73.8 circuit miles, North Central - South Central areas, operational 2010
- Uvalde Area Project, 138 kV, 77.5 circuit miles, South Central - West areas, operational 2011
- Zorn/Clear Springs-Gilleland Creek-Hutto Switch line addition, 345 kV, 172.5 circuit miles, South Central area, operational 2012.

Transmission projects approved in 2008 totaled \$255 million, and the amount for projects completed in 2008 was \$453 million.

Since 2008, ERCOT transmission service providers have completed more than 620 circuit miles of transmission lines and approximately 2,934 MVA of autotransformer capacity, with an estimated capital cost of \$629 million.

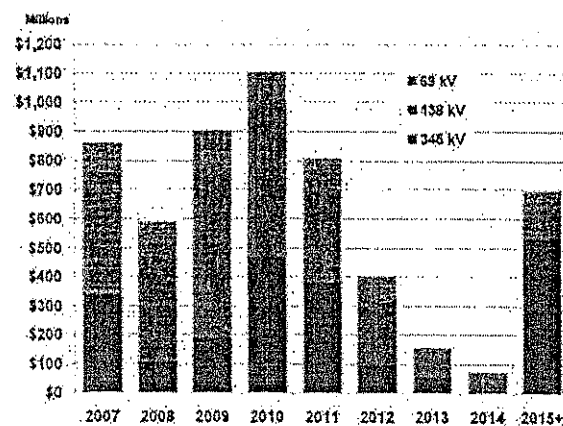
ERCOT staff completed the analyses and recommendations for 16 transmission projects through the Regional Planning Group review process and processed 140 generation interconnection requests and completed more than 146 interconnection screening studies.

Along with the five-year transmission report, ERCOT also filed the Long-Term System Assessment which looks at transmission and generation options for the next 10 years. The long-term system report is filed with the Texas Legislature in each even-numbered year, as required by Senate Bill 20, and is intended to provide guidance to ERCOT and ERCOT market participants in evaluating system needs.

Major conclusions in the 10-year report included:

- Additional import capacity into Houston is needed.
- Load growth in two areas (north of Dallas in Cooke and Grayson Counties and in western Williamson County) may result in the need for long-lead time transmission projects in the next 10 years.

TRANSMISSION IMPROVEMENTS



Numbers are based on projects being completed in the designated year and may not reflect actual investment in that year. Costs may be spread over several years.

RENEWABLE ENERGY

ERCOT Leads the Way

Commission approves plans for 18,000 MW of wind generation

ERCOT has continued to gain recognition as a national leader in integrating wind energy. At the end of 2008, ERCOT had more than 8,000 MW of installed wind generation, significantly ahead of the rest of the country, including Iowa, 2,790 MW, and California, 2,517 MW (Source: American Wind Energy Association). More than 2,000 MW of additional wind plants are scheduled to begin operations over the next two years, and approximately 50,000 MW are in various stages of interconnection studies.

Installation of wind generation has outpaced the capabilities of the current transmission system which can accommodate a maximum 4,500 MW of wind energy transfer from West Texas where it is located to load centers elsewhere in ERCOT. However, ERCOT again is leading the nation in expediting transmission to move power from the wind zones to the more populous areas. Last year the Public Utility Commission approved a \$5 billion transmission plan to support more than 18,000 MW of renewable generation. Construction on the new transmission may begin as early as 2010.

ERCOT system planning provided expert testimony and related support in development and designation of the Competitive Renewable Energy Zones and transmission plans, as directed by Texas Senate Bill 20 (2005) and the Public Utility Commission.

Renewable energy credit program leads the nation

The Texas Renewable Energy Credits (REC) program is the longest running and the most active in the country and is accomplishing its goal of helping to bring "clean" renewable resources into Texas at a record pace.

ERCOT administered the REC trading program for 93 resource entities in 2008, issuing more than 17.2 million RECs to Texas renewable energy generation companies — a 70 percent increase over 2007.

RECs are stock-like certificates that correspond to actual megawatts of renewable energy. Each REC represents one megawatt-hour of renewable energy produced.

The state's 135 competitive retail electricity providers retired 6.7 million RECs to satisfy the annual mandate within the portfolio standard. An additional 6.8 million RECs were retired in the voluntary market to substantiate "green energy" purchases, far surpassing last year's 1.6 million. This marked the first time that the voluntary retirements totaled more than the mandated retirements.

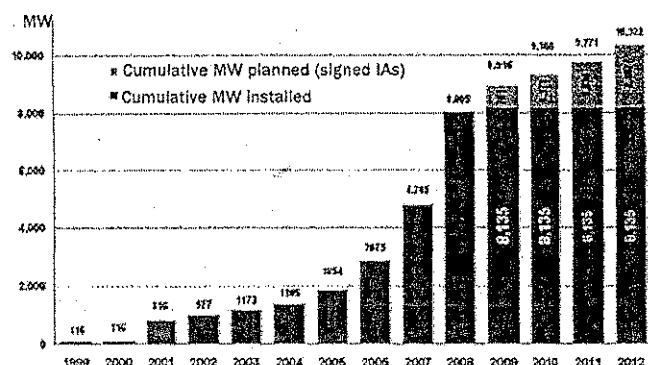
Under the Texas program, retail electric providers must acquire and retire RECs based on their load-ratio share of the renewable portfolio standard annual mandate. Electric providers may also retire RECs voluntarily to substantiate claims of green energy to consumers.

The REC trading program was established as part of the Legislature's restructuring of the state's electricity market in 1999 to increase incentives for renewable energy production through a renewable portfolio standard. The Texas program was the first of its kind in the nation when it began in 2001.

The original statutory goal of the program was to install 2,000 MW of additional, new renewable resource generation in Texas by the year 2009. That goal was surpassed three years ahead of schedule in 2006. The Legislature more than doubled the goal in 2007, making the target 5,000 MW by 2015 and 10,000 MW by 2025, including 500 MW from non-wind renewable resources such as solar, biomass, landfill gas and geothermal.

Texas has rapidly moved beyond the original goals. More than 7,000 MW of wind power has been added since 2001. The installed wind capacity in ERCOT was 8,005 MW at the end of 2008 and expected to pass 9,000 MW by the end of 2010.

INSTALLED WIND CAPACITY (MAY 2009)



MARKET OPERATIONS

Ensuring a Fair and Competitive Market

Retail transactions top 31 million since market launch

ERCOT is unique among independent system operators with its central role in assuring conveyance of retail customer switch requests, move-ins and move-outs, and meter-read data.

In 2008, ERCOT processed 4.7 million retail transactions – including retail switches, move-ins and move-outs and other transactions – above the 98 percent performance target for all four quarters. The total number of retail transactions completed since the market opened June 1, 2001 topped 31 million at the end of 2008.

The Texas retail electricity market continued to set the standard nationally for active customer switching. By year's end, 45 percent of residential customers were served by a retail electric provider other than the incumbent utility, compared with 41 percent in 2007. Also, 50 percent of the small commercial load and 75 percent of industrial load was served by a non-incumbent provider.

ERCOT coordinated and executed five market-wide mass-transition events during the year for competitive retailers who exited the market. The total number of transfers was 44,109 (comprised of 5,943 transferred to an acquiring competitive retailer and 38,166 transferred to a retailer designated as provider-of-last-resort). Each event was executed within the new timelines outlined by the market in 2007.

More than 19 new retail electric providers joined the ERCOT market in 2008, compared with 14 in 2007.

Settlements, billing staff process data for \$34 billion market

Managing the data and the wholesale settlements and billings processes that support the estimated \$34 billion market is a critical function of market operations. ERCOT staff processed more than 145,604 wholesale statements with 99 percent within protocol, and 8,244 invoices with 100 percent timeliness.

Other accomplishments in the markets division included:

- 99.96 percent accuracy on ERCOT polled-settlement meter data provided for settlements;

- 99.93 percent of interval data recorder metering data captured by true-up settlements.

ERCOT staff supports market, stakeholder process

ERCOT staff played a critical role in the stakeholder process by providing meeting management and technical support for numerous stakeholder meetings in 2008. The market rules staff managed all activities for 156 new revision requests and completed 553 recommendation reports. Market rules responded to more than 1,800 meeting requests, and provided support to the Technical Advisory Committee and its subcommittees for more than 140 days of meetings.

Retail client services staff provided business support for 101 market participant entities involved in day-to-day ERCOT operations, drafted and distributed 459 retail market notices, and delivered structured education sessions for 460 individuals.

Wholesale client services maintained a 99.35 percent rate for timely resolution of settlement disputes with a dispute volume averaging 140 disputes per month. Wholesale client services also delivered 364 hours of structured market training to 700 market participants and facilitated the complex start-up process of 19 new generation sites – an unprecedented number – deploying a new interconnect coordination process.

The market operations support staff captured approximately 22,000 interval data recorder usage reads per month in 2008.

The data integrity department completed an upgrade of the Lodestar application which added new functionality required for the nodal project and also improved batch processing times.

The testing department completed successful testing of ten capital projects, including execution of 4,919 test scripts, in addition to 3,122 test scripts for testing maintenance releases. The testing staff administered three market-wide test flights required for retail market certification. In addition, the department participated in ongoing nodal testing activities, executing more than 19,000 tests scripts and resolving over 1,700 defects.

NODAL MARKET IMPLEMENTATION

Market Redesign on Track for 2010 Completion

New integrated schedule keeping critical path on track

Texas Nodal Market Implementation is a complex engineering and business transformational program, involving hundreds of detailed workflows and processes. The project is expected to improve the market's price signals, dispatch efficiencies and its ability to directly assign local congestion, creating generation operating efficiencies that could be passed on to the consumer in the form of savings.

On February 17, 2009, the ERCOT Board of Directors approved a not-to-exceed budget of \$658.7 million for Texas Nodal's implementation work and an expanded schedule with a go-live date of December 2010.

A number of concrete actions have been taken to ensure Texas Nodal is completed on time and under budget:

- Hired energy consultant Utilicast to provide candid third-party assessments of the program's progress and risks;
- Created the Special Nodal Program Subcommittee of the Board to improve coordination between the committee, board and Utilicast;
- Hired a "nodal czar" to oversee nodal implementation and a market-readiness project leader to ensure market participants' systems are ready for nodal;
- Removed contingency funds from the nodal budget and placed them under board control;
- Approved a protocol revision that gives the ERCOT CEO discretion over future proposed nodal changes.

ERCOT is keeping Texas Nodal on schedule by maintaining tight controls over the program and budget. Critical-path activities are closely monitored. A formalized risk- and issue-management process ties into third-party audits and adds another layer of controls to delivery management. Key senior staff with extensive nodal-implementation experience have been brought on board.

The program's projects have been reorganized into core and supporting projects, replacing the previous silo project delivery with an enterprise program delivery approach. The integrated program schedule has helped

identify individual projects' impacts across the program. These moves have already paid strong dividends. Since Texas Nodal was re-planned in June 2008, it has hit all of its scheduled tasks on the critical path.

82 percent of core systems complete

Texas Nodal is a "best-of-breed" project using – for the first time anywhere – the Common Information Model (CIM) for integration of applications that use the network model. In January 2009, the nodal team prepared a CIM-based model, whose data fed into downstream market-management and energy management systems. These systems were able to import the CIM-based model's data and successfully run their own applications, moving ERCOT one step closer to an enterprise-integrated solution.

An estimated 82 percent of the core systems – those necessary to run the grid and market – have been developed. The bulk of the work that lies ahead includes integration and testing these systems, which has been underway since October 2008. Products must first pass functional acceptance testing of their stand-alone capabilities before they can enter the integrated testing environment, where their interfaces with other products are tested. Those systems will still have to be tested in the marketplace and with market participant systems – an estimated 10-month effort – and ERCOT and market participant users trained on those systems.

In February 2008, Texas Nodal completed an ERCOT-wide hardware/software/data migration, moving more than 40 terabytes of data into a new IBM environment to support nodal.

In June ERCOT successfully controlled the electric grid for two hours and completed a load-frequency test using the nodal systems. Other 2008 milestones include:

- Completion of a successful mock auction of Congestion Revenue Rights (March);
- ERCOT execution of day-ahead and adjustment-period markets (May);
- Testing of application interfaces (began in October);
- First-time State Estimator standard with improved telemetry, reaching the quality measure of 97 percent convergence (November).

TEXAS NODAL

At a Glance

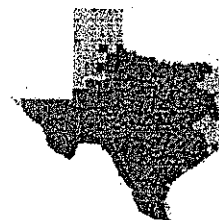
Zonal Market



In today's zonal market, the grid is divided into Congestion Management Zones (CMZs), which are defined by the Commercially Significant Constraints (CSCs). Several limitations have been identified with the current zonal model:

- Insufficient price transparency – This results in less efficient power dispatch, less efficient congestion management tools and muted or distorted signals for investment.
- Resources grouped by portfolio – Qualified scheduling entities (QSEs) submit schedules for a group of resources (portfolio) in a specific zone, and ERCOT operators have limited options to efficiently resolve congestion.
- Indirect assignment of local congestion – Participants who contribute to local congestion are not appropriately assigned the associated costs.

Nodal Market



Moving to a nodal design will satisfy the PUC order to directly assign local congestion. In the nodal market, the grid will consist of more than 4,000 nodes, replacing today's CMZs. The Texas Nodal design is expected to achieve lower overall costs through:

- Improved price signals – More granular pricing will encourage additional generation and/or transmission investment in the proper locations.
- Improved dispatch efficiencies – Dispatching at the resource level will yield a lower overall cost of power supply and more efficient congestion management.
- More direct assignment of local congestion – Settlement prices are based on locational marginal costs.

SUMMARY OF CHANGES

Today's Zonal Market

Tomorrow's Nodal Market

Transmission congestion rights	Congestion management rights
No day-ahead energy market	Day-ahead energy and ancillary services co-optimized market
Day-ahead market for ancillary services procured for capacity	
Replacement reserve service and procurement capacity	Day-ahead reliability unit commitment
Hour-ahead studies	Hourly reliability unit commitment
Portfolio-based offers by zone	Resource-specific local congestion
Balancing energy service (BES) every 15 minutes	Security constrained economic dispatch generally every five minutes (still 15-minute settlement)
Zonal congestion management by portfolio for CSCs	All congestion management will be resource-specific
Resource-specific for local congestion	Enhanced load frequency control
Zonal average shift factors for resources	Actual shift factors for resources
Zonal market clearing prices for BES for generation and loads	Nodal locational marginal pricing (LMP) for generation
	Zonal weighted LMP for loads

ERCOT MEMBERS

2008

CONSUMERS

Air Liquide Large Industries US
Air Products and Chemicals
Austin White Lime
BOC Gases
Chaparral Steel Midlothian
Chevron USA
CMC Steel Texas
Dow Chemical Company (The)
EPCO Holdings
Halliburton Energy Services
Lyondell Chemical Company
Marathon Petroleum Company
Nucor
Occidental Chemical Corp.
Pioneer Natural Resources USA
Praxair
Shell Oil Products
Texas Industries
Texas Instruments
Valero Services

Associate Member
Nustar Logistics

LARGE COMMERCIAL CONSUMERS

City of Abilene
City of Alamo
City of Alice
City of Allen
City of Arlington
City of Brownwood
City of Carrollton
City of Corpus Christi
City of Dallas
City of Dilley
City of Duncanville
City of Eules
City of Farmers Branch
City of Harker Heights
City of Irving
City of Killeen
City of La Feria
City of Lewisville
City of McAllen
City of McKinney
City of Mercedes
City of Midlothian
City of Mission
City of Missouri City

City of North Richland Hills
City of Odessa
City of Plano
City of Port Aransas
City of Portland
City of Port Lavaca
City of Rockport
City of San Angelo
City of Sherman
City of Sugar Land
City of Sweetwater
City of Texas City
City of The Colony
City of Tyler
City of Victoria
City of Waxahachie
HEB Grocery Company
Town of Addison
Town of Flower Mound
Wal-Mart Stores

RESIDENTIAL CONSUMERS

Office of Public Utility Counsel
TAC Residential Consumer Representative

SMALL COMMERCIAL CONSUMERS

City of Bedford
City of Belton
City of Benbrook
City of Carrizo Springs
City of Cedar Hill
City of Charlotte
City of Cisco
City of Cleburne
City of Colleyville
City of Colorado City
City of Commerce
City of Copperas Cove
City of Corinth
City of Crockett
City of Eastland
City of Forest Hill
City of Frisco
City of Gainesville
City of George West
City of Grand Prairie
City of Harlingen
City of Los Fresnos
City of Murphy

City of Ovilla
City of Paris
City of Point Comfort
City of Red Oak
City of Robinson
City of Rowlett
City of Snyder
City of University Park
City of Whitney
City of Woodway
J. C. Penney Corporation
Town of Highland Park
Town of Laguna Vista
Town of South Padre Island
Town of Woodsboro

Associate Member
Travis Wolff

COOPERATIVES

Bandera Electric Cooperative
Bartlett Electric Cooperative
Brazos Electric Power Cooperative
Coleman County Electric Cooperative
Comanche Electric Cooperative
Concho Valley Electric Cooperative
Cooke County Electric Cooperative
CoServ Electric
Fort Belknap Electric Cooperative
Golden Spread Electric Cooperative
Grayson-Collin Electric Cooperative
Guadalupe Valley Electric Cooperative
Hamilton County Electric Cooperative
Heart of Texas Electric Cooperative
HILCO Electric Cooperative
J-A-C Electric Cooperative
Karnes Electric Cooperative
Lower Colorado River Authority
Magic Valley Electric Cooperative
Medina Electric Cooperative
Mid-South Electric Cooperative Synergy
Navarro County Electric Cooperative
Navasota Valley Electric Cooperative
Nueces Electric Cooperative
Rayburn Country Electric Cooperative
Rio Grande Electric Cooperative
San Bernard Electric Cooperative
San Patricio Electric Cooperative
South Plains Electric Cooperative
South Texas Electric Cooperative
Southwest Texas Electric Cooperative

Tri-County Electric Cooperative
 United Electric Cooperative Services
 Victoria Electric Cooperative
 Wharton County Electric Cooperative
 Wise Electric Cooperative

INDEPENDENT GENERATORS

AES Corporation
 Airtricity
 Calpine Corporation
 Cielo Wind Power
 Dynegy Power Corp.
 Edison Mission Marketing & Trading
 Formosa Plastics Corp., Texas
 FPL Energy
 Gregory Power Partners
 International Power America Svc
 Invenergy Wind Development
 Kelson Energy Inc.
 Navasota Energy Management
 NRG Texas
 PSEG Texgen I
 RES America Developments
 Signal Hill Wichita Falls Power
 Suez Energy Marketing NA
 Sweetwater Wind 2
 Topaz Power Group LLC
 Westar Energy
 Wolf Hollow I

Associate Members

Bosque Power Company
 Constellation Energy Control Guadalupe-
 Blanco River Auth.
 NuCoastal Power Corporation
 PSEG Texas
 Tenaska Energy
 Texas Petrochemicals
 Whirlwind Energy

INDEPENDENT POWER MARKETERS

Aquila Inc. dba Aquila Networks
 Bear Energy
 BP Energy
 Cargill Power Markets
 Citigroup Energy

Constellation Energy Commodities
 Coral Power
 DB Energy Trading
 Endure Energy
 EPIC Merchant Energy TX
 Exelon Generation Company
 Fortis Energy Marketing & Trading
 J. Aron & Company
 Keystone Energy Partners
 Lehman Brothers Commodity Services
 Morgan Stanley Capital Group
 North American Energy Credit and
 Clearing-Delivery LLC
 PPM Energy Inc.
 Rainbow Energy Marketing
 Reliant Energy
 Tenaska Power Services Co.
 UBS AG, London Branch
 Associate Members
 ConocoPhillips Company
 Eagle Energy Partners I
 Edison Mission Mktg & Trading
 Occidental Power Services
 PSEG Energy Resources
 Xtend Energy

INDEPENDENT RETAIL ELECTRIC PROVIDERS

Accent Energy Texas
 Cirro Group
 Cities Aggregation Power Project
 Commerce Energy
 Consolidated Edison Solutions
 Direct Energy
 Energy Services Providers of Texas
 Green Mountain Energy Company
 Integrys Energy Services of Texas
 Just Energy Texas LP dba US Energy
 Savings
 Liberty Power Texas
 Pepco Energy Services
 Sempra Energy Solutions
 South Texas Aggregation Project
 Spark Energy
 StarTex Power
 Strategic Energy
 Stream SPE Ltd. dba Stream Energy
 Tara Energy
 Texas Power
 TriEagle Energy

Associate Members

Ambit Energy
 Andeler Corporation
 Blu Power of Texas
 BOC Energy Services
 Brubaker & Associates
 Champion Energy Services
 Constellation NewEnergy
 Econnergy Energy Co. Inc.
 Gexa Energy
 Himalaya Power
 J. Pollock
 Sitara Energy
 Suez Energy Resources NA

INVESTOR-OWNED UTILITIES

American Electric Power Service
 Corporation
 CenterPoint Houston Electric
 First Choice Power Special Purpose
 Oncor Electric Delivery Company
 Sharyland Utilities
 Associate Members
 Electric Transmission Texas
 EnergyCo Marketing & Trading
 Luminant Generation Company
 Texas-New Mexico Power Company
 TXU Energy Retail Company

MUNICIPALS

Austin Energy
 Brownsville Public Utilities
 Bryan Texas Utilities
 City of College Station
 City of Georgetown
 CPS Energy
 Denton Municipal Electric
 Floresville Electric Light & Power System
 Garland Power & Light
 GEUS
 Kerrville Public Utility Board
 New Braunfels Utilities
 Texas Municipal Power Agency

Associate Member

City of Bastrop

FIVE-YEAR SUMMARY

Financial, Operating, Retail Transactions Data

FINANCIAL DATA (\$/millions)	2004	2005	2006	2007	2008
Revenue	129.7	127.9	135.1	165.9 ¹	187.0 ²
Direct Operating Expenses	79.1	80.8	85.9	115.8	141.1
Depreciation/Amortization	44.7	49.0	42.2	33.9	31.9
Net Interest Expense/(Income)	8.0	7.7	5.4	4.3	7.0
Total Expenses	131.8	137.5	133.5	154.0	180.0
Debt: Long Term	149.0	134.1	108.0	181.8	280.7
Debt: Short Term	29.4	26.1	73.1	77.1	60.2
Capital Expenditures	59.7	25.3	68.2	132.7	139.8
Administration Fee (per MWh)	\$0.44	\$0.42	\$0.417	\$0.417	\$0.417

NOTE: 2008 Audited Financial Statements (PricewaterhouseCoopers) are posted on www.ercot.com in News/Reports section.

OPERATING DATA	2004	2005	2006	2007	2008
Peak Demand (MW)	58,531	60,274	62,339	62,188	62,174
Energy (GWh)	289,113	299,219	305,692	307,064	312,401
Reserve Margin (%)	25.2	16.5	16.4	14.6	13.8
Transmission Improvements (\$ millions) ³	\$360.1	\$557.4	\$749.4	\$919.5	\$453.0
Wind Generation, Cumulative (MW)	1,385	1,854	2,875	4,785	8,005
Local Congestion Costs (\$ millions) ⁴	\$279.0	\$266.6	\$183.6	164.4	184.2

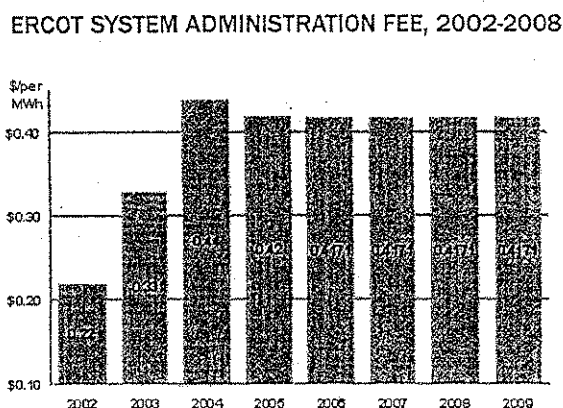
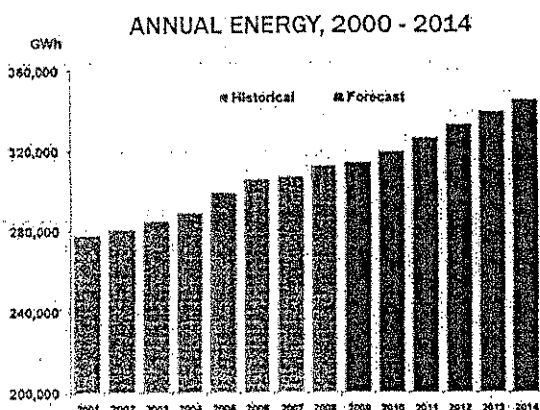
RETAIL TRANSACTIONS DATA	2004	2005	2006	2007	2008
Competitive Choice Customers (millions)	6.1	6.2	6.3	6.4	6.5
Switches Completed (cumulative)	1,646,346	2,287,492	3,134,197	3,849,436	4,762,043
Switches by Year	457,517	641,146	846,705	715,239	822,607
Residential	335,253	479,830	656,218	578,727	662,566
Small Non-residential	121,210	160,339	189,482	135,586	159,216
Large Non-residential	1,054	976	1,004	926	825
Migration from Native Affiliate Retail Electric Provider					
Residential (%)	21.4	30.2	37.9	43.2	46.2
Small Non-Residential (%)	59.1	66.2	70.0	72.9	75.5
Large Non-Residential (%)	64.7	71.8	72.4	73.0	73.6
Competitive Retail Total Transactions (000's)	89,060	92,368	94,857	93,684	95,440

¹ Includes \$32 million from nodal surcharge and \$2 million from NERC ERO fee

² Includes \$47.8 million from nodal surcharge and \$2.1 million from NERC ERO fee

³ Based on projects completed in the designated year; may not reflect annual costs since costs may be spread over several years

⁴ Methodology has changed during the five-year period. Past years' updated to reflect changes following re-settlements and true-ups.



ERCOT GOVERNANCE

Board of Directors

Chairman

Jan Newton
Chairman
(unaffiliated)

Vice Chairman

Michael Gent
Vice Chairman
(unaffiliated)

Mark Armentrout
(unaffiliated)

Don Ballard
Office of Public Utility
Counsel
(residential consumer,
ex-officio)

Brad Cox
Tenaska Power Services
(independent power
marketer)

Andrew Dalton
Valero Energy Corporation
(industrial consumer)

Miguel Espinosa
(unaffiliated)

Nick Fehrenbach
City of Dallas
(commercial consumer)

Bob Helton
International Power
America
(independent generator)

Charles Jenkins
Oncor Electric Delivery
(investor-owned utility)

Bob Kahn
CEO, ERCOT
(ex-officio)

Clifton Karnel
Brazos Electric
Cooperative
(cooperative)

Alton D. "Dee" Patton
(unaffiliated)

Barry T. Smitherman
Chairman
Public Utility Commission
(ex-officio, non-voting)

Robert Thomas
Green Mountain Energy
(retail electric provider)

Dan Wilkerson
Bryan Texas Utilities
(municipal utility)

Segment Alternates

Steve Bartley
CPS Energy
(municipal utility)

Deryl Brown
Hudson Energy Services
(retail electric provider)

Calvin Crowder
Electric Transmission
Texas (investor-owned
utility)

Mike Packard
South Texas Electric
Cooperative (cooperative)

Jean Ryall
Constellation Energy
Commodities
(independent power
marketer)

Mark Walker
NRG Texas
(independent generator)

ERCOT Officers

Bob Kahn
President and
Chief Executive Officer

Mike Cleary
Senior Vice President and
Chief Technology Officer

H.B. "Trip" Doggett
Senior Vice President and
Chief Operations Officer

Steve Byone
Vice President and
Chief Financial Officer

Nancy Capezzuti
Vice President and
Chief Administrative Officer

Mike Grable
Vice President and
General Counsel

Charles B. Manning, Jr.
Vice President and
Chief Compliance Officer

Richard Morgan
Interim Vice President and
Chief Information Officer

Kent Saathoff
Vice President of System
Planning and Operations

Board, Stakeholder Process

The ERCOT Board of Directors has general overall responsibility for managing the affairs of ERCOT, including approval of the budget and capital spending priorities, approval of revisions to ERCOT protocols and guides, and endorsement of major new transmission infrastructure recommendations. ERCOT's 16-member "hybrid" board includes five independent (or unaffiliated) members; three consumer segment representatives (industrial, commercial and residential); the ERCOT CEO; the Public Utility Commission chairman (non-voting), and six representatives from each of the industry segments – investor-owned utilities (or transmission owners), municipally-owned utilities, cooperatives, generators, power marketers and retail electric providers.

The Board also oversees the affairs of the Texas Regional Entity (Texas RE), the independent division that FERC established in 2006 to serve as the regional entity for the ERCOT region, pursuant to the reliability provisions of the federal Energy Policy Act of 2005 (EPAct).

Under the Board's oversight, ERCOT's stakeholder process is responsible for developing policies, procedures, and guidelines for power grid coordination, reliability, and market operations. Six standing committees and subcommittees supported by numerous working groups and task forces function within the stakeholder process.

Legislative Oversight

Other than on issues arising under federal EPAct provisions, ERCOT is subject to oversight by the Texas Legislature and is fully regulated by the Public Utility Commission of Texas (PUC). The PUC approves the ERCOT system administration fee, which provides 98 percent of ERCOT's revenues, and has general oversight authority including the ability to conduct or order audits. Texas RE funds under EPAct are administered separately. For most purposes, ERCOT, like the PUC, is accountable to the Texas Legislature and its jurisdictional committees. For EPAct purposes, ERCOT is accountable to the Texas RE, NERC, and the Federal Energy Regulatory Commission.

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to approximately 22 million Texas customers – representing 85 percent of the state's electric load and 75 percent of the Texas land area. As the Independent System Operator for the region, ERCOT schedules power on an electric grid that connects 40,000 miles of transmission lines and more than 550 generation units. ERCOT also manages financial settlement for the competitive wholesale bulk-power market and administers customer switching for 6.5 million Texans in competitive choice areas. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature.



Electric Reliability Council of Texas, Inc.

Austin
7620 Metro Center Drive
Austin TX 78744
512/225-7000

Taylor
2705 West Lake Drive
Taylor TX 76574
512/248-3000



Cornell University
Law School

LI

/ Legal Information Institute

U.S. Code

[main page](#) [faq](#) [index](#) [search](#)

Régie de l'énergie

DOSSIER: 12-3669-2008

DÉPOSÉE EN AUDIENCE

Phase 2

Date: 7/05/2011

Pièces n°: 13-233

[Search Law School](#) [Search Cornell](#)

[home](#) [search](#) [find a lawyer](#) [donate](#)



TITLE 16 > CHAPTER 12 > SUBCHAPTER II > § 824j-1

§ 824j-1. Open access by unregulated transmitting utilities

(a) Definition of unregulated transmitting utility

In this section, the term "unregulated transmitting utility" means an entity that--

- (1) owns or operates facilities used for the transmission of electric energy in interstate commerce; and
- (2) is an entity described in section 824 (f) of this title.

(b) Transmission operation services

Subject to section 824k (h) of this title, the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services--

- (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and
- (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.

(c) Exemption

The Commission shall exempt from any rule or order under this section any unregulated transmitting utility that--

- (1) sells not more than 4,000,000 megawatt hours of electricity per year;
- (2) does not own or operate any transmission facilities that are necessary for operating an interconnected transmission system (or any portion of the system); or
- (3) meets other criteria the Commission determines to be in the public interest.

(d) Local distribution facilities

The requirements of subsection (b) of this section shall not apply to facilities used in local distribution.

(e) Exemption termination

If the Commission, after an evidentiary hearing held on a complaint and after giving consideration to reliability standards established under section 824o of this title, finds on the basis of a preponderance of the evidence that any exemption granted pursuant to subsection (c) of this section unreasonably impairs the continued reliability of an interconnected transmission system, the Commission shall revoke the exemption granted to the transmitting utility.

(f) Application to unregulated transmitting utilities

The rate changing procedures applicable to public utilities under subsections (c) and (d) of section 824d of this title are applicable to unregulated transmitting utilities for purposes of this section.

(g) Remand

In exercising authority under subsection (b)(1) of this section, the Commission may remand transmission rates to an unregulated transmitting utility for review and revision if necessary to meet the requirements of subsection (b) of this section.

(h) Other requests

The provision of transmission services under subsection (b) of this section does not preclude a request for transmission services under section 824j of this title.

(i) Limitation

The Commission may not require a State or municipality to take action under this section that would violate a private activity bond rule for purposes of section 141 of title 26.

(j) Transfer of control of transmitting facilities

Nothing in this section authorizes the Commission to require an unregulated transmitting utility to transfer control or operational control of its transmitting facilities to a Transmission Organization that is designated to provide nondiscriminatory transmission access.

2009 BPA facts

Unless otherwise noted, information is for fiscal year 2009.

Profile

The Bonneville Power Administration is a federal nonprofit agency based in the Pacific Northwest. Although BPA is part of the U.S. Department of Energy, it is self-funding and covers its costs by selling its products and services. BPA markets wholesale electrical power from 31 federal hydro projects in the Columbia River Basin, one nonfederal nuclear plant and several other small nonfederal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. About one-third of the electric power used in the Northwest comes from BPA.

BPA also operates and maintains about three-fourths of the high-voltage transmission in its service territory. BPA's service territory includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.

As part of its responsibilities, BPA promotes energy efficiency, renewable resources and new technologies. The agency also funds regional efforts to protect and rebuild fish and wildlife populations affected by hydropower development in the Columbia River Basin.

BPA is committed to providing public service and seeks to make its decisions in a manner that provides opportunities for input from all stakeholders. In its vision statement, BPA dedicates itself to providing high system reliability, low rates consistent with sound business principles, environmental stewardship and accountability.

General Information

BPA established	1937
Service area size (square miles)	300,000
Pacific Northwest population	12,434,934
Transmission line (circuit miles)	15,212
BPA substations	260
Employees (FTE)	3,100

Customers

Cooperatives	57
Municipalities	42
Public utility districts	29
Federal agencies	7
Investor-owned utilities	6
Direct-service industries	3
Port districts	1
Tribal utilities	2
Total	147

Région de l'énergie	168 ¹⁷
Transmission customers	385

17/ This number now includes both power and transmission markets.

Previous editions of BPA Facts only listed the number of power marketers.

DOSSIER: R-3664 2008 Phase 2

DEPOSÉE EN AUDIENCE

Date: 11/05/2011

Pièces n°: B-235

BPA Mission

The Bonneville Power Administration's mission as a public service organization is to create and deliver the best value for our customers and constituents as we act in concert with others to assure the Pacific Northwest:

- an adequate, efficient, economical and reliable power supply;
- a transmission system that is adequate to the task of integrating and transmitting power from federal and nonfederal generating units, providing service to BPA's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and
- mitigation of the Federal Columbia River Power System's impacts on fish and wildlife.

BPA is committed to cost-based rates and public and regional preference in its marketing of power. BPA will set its rates as low as possible consistent with sound business principles and the full recovery of all of its costs, including timely repayment of the federal investment in the system.

BPA Vision

BPA will be an engine of the Northwest's economic prosperity and environmental sustainability. BPA's actions advance a Northwest power system that is a national leader in providing:

- high reliability;
- low rates consistent with sound business principles;
- responsible environmental stewardship; and
- accountability to the region.

We deliver on these public responsibilities^{2/} through a commercially successful business.

2/ Our public responsibilities are defined by the four characteristics listed above.

Rates

Wholesale power rates^{3/} (10/1/09-9/30/10)

Non-Slice Priority Firm (average, undelivered)	2.88 cents/kWh
Priority Firm Exchange (average, undelivered)	4.87 cents/kWh
New Resources (flat, undelivered)	6.87 cents/kWh

3/ The rates shown do not include the cost of transmission. They also do not include the application of the Conservation Rate Credit.

4/ The actual rate paid by an individual customer will vary according to the shape of the load and the products and services purchased.

Transmission rates^{5/} (FYs 2010-2011)

Network rates:	
Firm	\$15.576/kW/yr
Nonfirm	.374 cents/kWh

Southern intertie rates:

Firm	\$15.516/kW/yr
Nonfirm	.372 cents/kWh

5/ Reflects the rates for point-to-point transmission service. All short-term firm and nonfirm rates are downwardly flexible.

2009 Financial Highlights

For the Federal Columbia River Power System

(\$ in thousands)

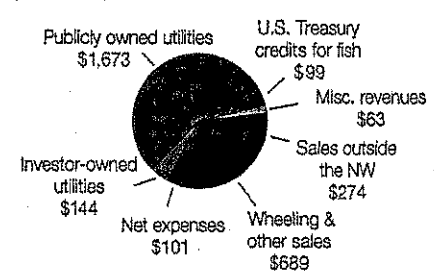
Total operating revenues ^{6/}	\$2,870,284
Total operating expenses	2,752,905
Net operating revenues	117,379
Net interest expense	218,429
Net expenses	(101,050)
Derivative instruments	\$ 34,677
Nonfederal debt management actions	(120,853)
Modified net expenses ^{7/}	\$(187,226)

6/ Includes both power and transmission revenues.

7/ Management has determined that modified net revenues (expenses) are a better representation of the outcomes of normal operations during periods of debt management actions and fluctuations in derivative market prices. See BPA's 2009 Annual Report for more information.

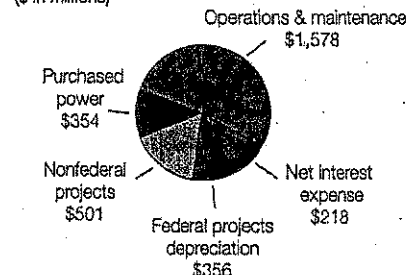
Sources of revenue^{8/ 9/}

(\$ in millions)



Disposition of revenue^{8/}

(\$ in millions)



8/ Does not reflect bookouts of ~\$37 million.

9/ Does not reflect derivative instruments of ~\$35 million.

Transmission System

Operating voltage	Circuit miles
1,000 kV	264 ^{10/}
500 kV	4,734
345 kV	570
287 kV	227
230 kV	5,319
161 kV	119
138 kV	50
115 kV	3,556
below 115 kV	373
Total	15,212

10/ BPA's portion of the PNW/PSW direct-current intertie. The total length of this line from The Dalles, Ore., to Los Angeles is 1,446 miles.



Federal Hydro Projects

Name	River, state	In service	Nameplate rating
Alberici Falls	Pend Oreille, ID	1955	43 MW
Anderson Ranch	Boise, ID	1950	40 MW
Big Cliff	Santiam, OR	1953	18 MW
Black Canyon	Payette, ID	1925	10 MW
Boise River Diversion	Boise, ID	1912	3 MW
Bonneville	Columbia, OR/WA	1938	1,077 MW
Chandler	Yakima, WA	1956	12 MW
Chief Joseph	Columbia, WA	1958	2,458 MW
Cougar	McKenzie, OR	1963	25 MW
Detroit	Santiam, OR	1953	100 MW
Dexter	Willamette, OR	1954	15 MW
Dworshak	Clearwater, ID	1973	400 MW
Foster	Santiam, OR	1967	20 MW
Grand Coulee ^{12/}	Columbia, WA	1942	6,755 MW
Green Peter	Santiam, OR	1967	80 MW
Green Springs	Emigrant Crk, OR	1960	18 MW
Hills Creek	Willamette, OR	1962	30 MW
Hungry Horse	Flathead, MT	1953	428 MW
Ice Harbor	Snake, WA	1962	603 MW
John Day	Columbia, OR/WA	1971	2,160 MW
Libby	Kootenai, MT	1975	525 MW
Little Goose	Snake, WA	1970	810 MW
Lookout Point	Willamette, OR	1953	120 MW
Lost Creek	Rogue, OR	1977	49 MW
Lower Granite	Snake, WA	1975	810 MW
Lower Monumental	Snake, WA	1969	810 MW
McNary	Columbia, OR/WA	1952	980 MW
Minidoka	Snake, ID	1909	28 MW
Palisades	Snake, ID	1958	176 MW
Roza	Yakima, WA	1958	11 MW
The Dalles	Columbia, OR/WA	1957	1,808 MW
Total (31 dams)			20,430 MW

Owned and operated by the U.S. Army Corps of Engineers (21 dams, 12,940 MW)
Owned and operated by the Bureau of Reclamation (10 dams, 7,490 MW).

11/ Includes pump generation.

BPA Resources^{12/}

(for OY 2010 under 1937 water conditions)

Sustained 1-hour peak capacity (January) 18,326 MW

Hydro: 16,332 MW (89.1%)

Nuclear: 1,150 MW (6.3%)

Firm contracts & other resources: 844 MW (4.6%)

Firm energy (12-month annual avg.) 8,862 aMW

Hydro: 6,983 aMW (78.8%)

Nuclear: 1,030 aMW (11.6%)

Firm contracts & other resources: 849 aMW (9.6%)

Regional Resources^{12/}

(for OY 2010 under 1937 water conditions)

Sustained peak capacity (January) 45,603 MW

Hydro: 27,142 MW (59.5%)

Coal: 5,866 MW (12.9%)

Combustion turbines: 5,526 MW (12.1%)

Cogeneration: 2,938 MW (6.4%)

Imports: 2,094 MW (4.6%)

Nuclear: 1,150 MW (2.5%)

Non-utility generation: 630 MW (1.4%)

Other miscellaneous resources: 258 MW (0.6%)

Firm energy (12-month annual avg.) 26,033 aMW

Hydro: 11,842 aMW (45.5%)

Coal: 4,951 aMW (19.0%)

Combustion turbines: 2,824 aMW (10.8%)

Cogeneration: 2,530 aMW (9.7%)

Imports: 1,239 aMW (4.8%)

Nuclear: 1,030 aMW (4.0%)

Non-utility generation: 626 aMW (2.4%)

Other miscellaneous resources: 991 aMW (3.8%)

12/ Forecast figures from BPA's draft "2009 Pacific Northwest Loads & Resources Study." Firm resource projections before adjustment for reserves, maintenance and transmission losses. The hydro capacity is reduced by an operational peaking adjustment to estimate the monthly maximum operational capability that is available to meet the 1-hour peak load for 1937 critical-water conditions. For January 2010, the reduction is 4,526 peak MW.

Federal Generation (FY 2009)

Hydro generation	7,588 aMW
Total generation	8,406 aMW
60-min. hydro peak generation	15,256 MW
60-min. total peak generation	15,914 MW
All-time 60-min. total peak generation record (June 2002)	18,139 MW

Fish & Wildlife Costs

(\$ in millions)

	FY 2009
BPA F&W program expense ^{13/} (does not include \$25.5 million capital)	\$178
Direct funded/reimbursable	64
Capital investment/expense	120
Total direct costs	\$362
Operational impacts:	
Replacement power purchases	\$240
Estimated foregone power revenues	143
Total F&W costs for FY 2009	\$745

BPA has committed more than \$11 billion since 1978 to support Northwest fish and wildlife recovery.

13/ Integrated program and action plan/high priority.

Conservation

(\$ in millions)

	FY 2009	Total ^{14/}
Total BPA expenses	\$72	\$2,366
Megawatts saved		
Residential programs	20.2 aMW	304.2 aMW
Commercial programs	20.3 aMW	222.2 aMW
Industrial programs	7.6 aMW	132.9 aMW
Agricultural programs	2.1 aMW	23.7 aMW
Multi-sector programs	1.0 aMW	108.9 aMW
Programs subtotal	51.1 aMW	792.0 aMW
Improved building codes	0 aMW	188.5 aMW
Market transformation	12.6 aMW	155.6 aMW
Total aMW saved	63.7 aMW	1,136.1 aMW

14/ Cumulative total since 1981. Adjustments to savings and dollars have been applied.

Points of Contact

General BPA offices & Web sites

BPA Headquarters — 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208 • 503-230-3000 • www.bpa.gov

Public Information Center — 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208 • 503-230-INFO [4636] • 800-622-4520

Community Engagement — P.O. Box 14428, Portland, OR 97293-4428 • 800-622-4519

Washington, D.C. Office — Forrestal Bldg., Room 8G-061, 1000 Independence Ave., S.W., Washington, DC 20585 • 202-586-5640

Crime Witness Program — To report crimes to BPA property or personnel • 800-437-2744

Transmission Services

Transmission Services Headquarters — P.O. Box 491, Vancouver, WA 98666-0491 • 360-418-2000

Covington District Office — 28401 Covington Way S.E., Kent, WA 98402 • 253-638-7376

Eugene District Office — 86000 Hwy. 99 S., Eugene, OR 97405 • 541-988-7401

Idaho Falls Regional Office — 1350 Lindsay Blvd., Idaho Falls, ID 83402 • 208-612-3110

Kalispell District Office — 2520 U.S. Hwy. 2 East, Kalispell, MT 59901 • 406-751-7897

Longview District Office — 3750 Memorial Park Drive, Longview, WA 98632 • 360-414-5601

Olympia Regional Office — 5240 Trosper Rd. S.W., Olympia, WA 98512-5623 • 360-570-4301

Redmond District Office — 3655 S.W. Highland Ave., Redmond, OR 97756 • 541-548-4015, Ext. 3225

Salem District Office — 2715 Tepper Lane N.E., Kelso, OR 97303 • 503-393-2638

Snohomish District Office — 914 Ave. D, Snohomish, WA 98290 • 360-563-3602

Spokane District Office — 2410 E. Hawthorne Rd., Mead, WA 99021 • 509-358-7379

The Dalles District Office — 3920 Columbia View Dr. East, The Dalles, OR 97058 • 541-296-4694

Tri-Cities District Office — 3404 Swallow Ave., Pasco, WA 99301 • 509-542-5430

Wenatchee District Office — 13294 Lincoln Park Rd., East Wenatchee, WA 98802 • 509-886-6001

Power Services

Bend Customer Service Center — 1011 S.W. Emkay Dr., Suite 211, Bend, OR 97702 • 541-318-1680

Burley Customer Service Center — 2700 Overland, Burley, ID 83318 • 208-678-9481

Eastern Area Customer Service Center — 707 W. Main Ave., Suite 500, Spokane, WA 99201 • 509-625-1371

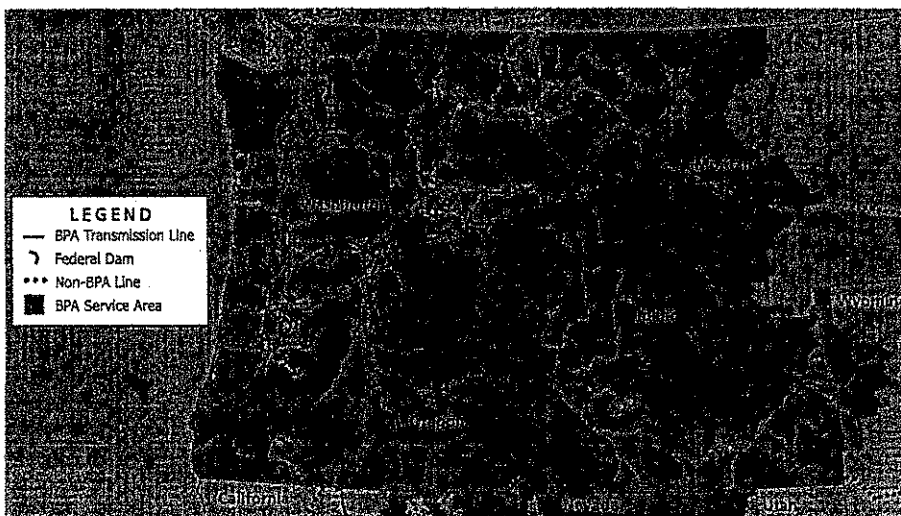
Montana Customer Service Center — P.O. Box 140, Dayton, MT 59914 • 406-849-5034

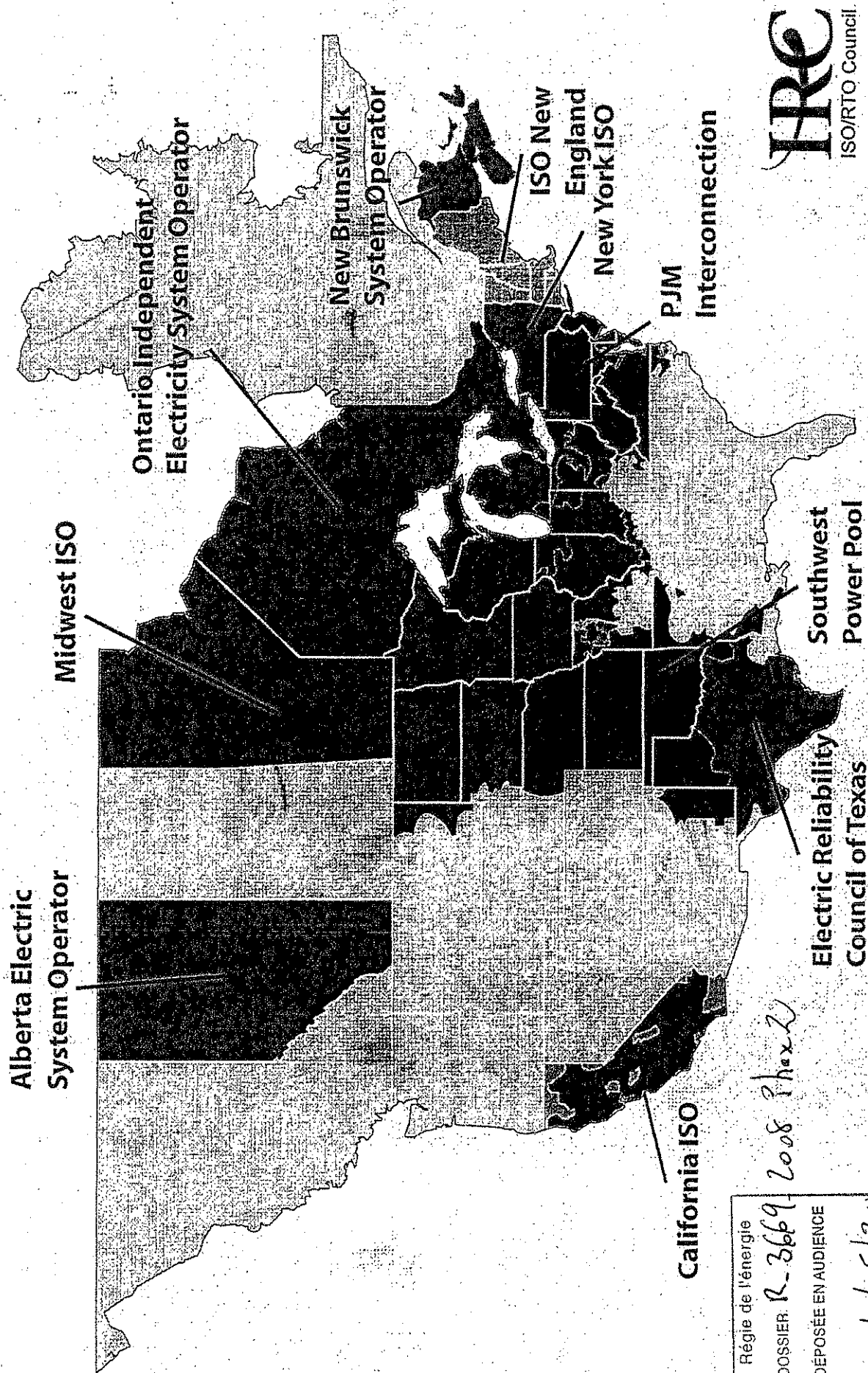
Richland Customer Service Center — Kootenai Bldg., Room 215, North Power Plant Loop, P.O. Box 968, Richland, WA 99352 • 509-372-5088

Seattle Customer Service Center — 909 First Ave., Suite 380, Seattle, WA 98104-3636 • 206-220-6770

Western Area CSC — 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208 • 503-230-5204

Transmission System and Federal Dams





Régie de l'énergie
 DOSSIER: R-3669-2008 Phax 2
 DÉPOSÉE EN AUDIENCE
 Date 10/05/2011
 Pièces n°: B-236



[About](#) | [Members](#) | [Newsroom](#) | [Documents and Issues](#) | [Links](#)

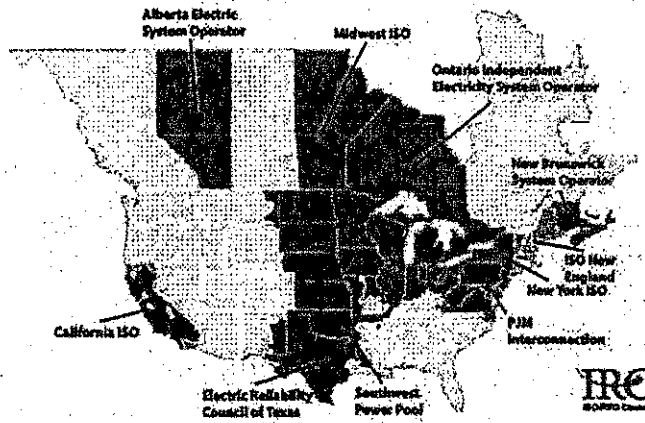
[IRC Committees](#)

[Contact the IRC](#)

[Map](#)

[> Home](#) > [About](#) > [Map](#)

ISO RTO Operating Regions



[Download a PDF version of the map, with labeling. \(557kb PDF\)](#)

[Download a PDF version of the map, without labeling. \(536kb PDF\)](#)

[Site Map](#) | [Terms and Conditions of Use](#) | © Copyright 2011 ISO/RTO Council

[About](#) | [Members](#) | [Newsroom](#) | [Documents and Issues](#) | [Links](#)[AESO](#)[CAISO](#)[ERCOT](#)[IESO](#)[ISONE](#)[MISO](#)[NBSO](#)[NYISO](#)[PJM](#)[SPP](#)[IRC At A Glance](#)[> Home > Members](#)

IRC Members

ISO/RTOs coordinate generation and transmission across a wide geographic area, matching generation instantaneously to the demand for electricity. They forecast load and schedule generation to assure that sufficient generation and back-up power is available if demand rises or a power plant or power line is lost.

In addition to coordinating electric generation and transmission, ISO/RTOs provide non-discriminatory transmission access, facilitate competition among wholesale electricity suppliers, and conduct regional planning to ensure a reliable grid for the future.

ISO/RTOs are also improving grid reliability and driving innovation in grid management technology and effectiveness, including data visualization for system operations, faster contingency analysis and data interpretation, and cyber-security protection measures.

Links in the right column will take you to pages about each IRC member, and the [IRC At a Glance](#) page summarizes each member's miles of transmission lines, installed generation, and population.

[Site Map](#) | [Terms and Conditions of Use](#) | © Copyright 2011 ISO/RTO Council

Régie de l'énergie
DOSSIER: 12-3669-2008 Phox 2
DÉPOSÉE EN AUDIENCE
Date: 10/05/2011
Pièces n°: 13-237

131 FERC ¶ 61,253

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-23-000]

Transmission Planning and Cost Allocation by Transmission
Owning and Operating Public Utilities

(Issued June 17, 2010)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission is proposing to amend the transmission planning and cost allocation requirements established in Order No. 890 to ensure that Commission-jurisdictional services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. With respect to transmission planning, the proposed rule would (1) provide that local and regional transmission planning processes account for transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) improve coordination between neighboring transmission planning regions with respect to interregional facilities; and (3) remove from Commission-approved tariffs or agreements a right of first refusal created by those documents that provides an incumbent transmission provider with an undue advantage over a nonincumbent transmission developer. Neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved tariff or agreement, receive different treatment in a regional transmission

planning process. Further, both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. With respect to cost allocation, the proposed rule would establish a closer link between transmission planning processes and cost allocation and would require cost allocation methods for intraregional and interregional transmission facilities to satisfy newly established cost allocation principles.

DATES: Comments are due [insert date that is 60 days after publication in the **FEDERAL REGISTER**].

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- Agency Web Site: <http://www.ferc.gov>. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- Mail/Hand Delivery: Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE, Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document

FOR FURTHER INFORMATION CONTACT:

Russell Profozich
Federal Energy Regulatory Commission
Office of Energy Policy and Innovation
888 First Street, NE
Washington, DC 20426
(202) 502-6478

John Cohen
Federal Energy Regulatory Commission
Office of the General Counsel
888 First Street, NE
Washington, DC 20426
(202) 502-8705

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation by
Transmission Owning and Operating Public Utilities

Docket No. RM10-23-000

NOTICE OF PROPOSED RULEMAKING

TABLE OF CONTENTS

	<u>Paragraph Numbers</u>
I. Introduction	1.
II. Background	6.
A. Order Nos. 888 and 890	6.
B. Technical Conferences and Notice of Request for Comments on Transmission Planning and Cost Allocation	13.
C. Additional Developments Since Issuance of Order No. 890	25.
III. The Need for Reform	32.
IV. Proposed Reforms: Transmission Planning	44.
A. Participation in the Regional Planning Process	45.
B. Public Policy Driven Projects	55.
C. Opportunities for Undue Discrimination against Nonincumbent Transmission Developers	71.
1. Nonincumbent Transmission Developer Participation in the Transmission Planning Process	71.
2. Proposed Reforms Regarding Nonincumbents	87.
D. Interregional Coordination	102.
1. The Need for Interregional Planning Reforms	102.
2. Proposed Interregional Planning Reforms	114.
V. Proposed Reforms: Cost Allocation	121.
A. Introduction	121.
1. Order No. 890's Transmission Planning Principle on Cost Allocation for New Transmission Facilities	121.

2. October 2009 Notice and Subsequent Comments	129.
B. Legal Authority and Need for Reform	138.
1. The Cost Causation Principle	139.
2. Need for Reform	148.
C. Proposed Reforms	155.
1. Intraregional Cost Allocation	164.
2. Interregional Cost Allocation	170.
VI. Compliance Filings	179.
VII. Information Collection Statement.....	182.
VIII. Environmental Analysis	186.
IX. Regulatory Flexibility Act Analysis.....	187.
X. Comment Procedures.....	188.
XI. Document Availability	192.

Regulatory Text

Appendix A: List of Short Names of Commenters on the Federal Energy Regulator Commission's Notice of Request for Comments on Transmission Planning Processes under Order No. 890—Docket No. AD09-8-000, October 2009

Appendix B: *Pro Forma* Open Access Transmission Tariff Attachment K

131 FERC ¶ 61,253
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation by
Transmission Owning and Operating Public Utilities

Docket No. RM10-23-000

NOTICE OF PROPOSED RULEMAKING

(Issued June 17, 2010)

I. Introduction

1. In this Notice of Proposed Rulemaking (Proposed Rule), the Federal Energy Regulatory Commission (Commission) is proposing to reform its electric transmission planning and cost allocation requirements for public utility transmission providers. The proposed reforms are intended to correct deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

2. This Proposed Rule builds on Order No. 890,¹ in which the Commission reformed the *pro forma* open access transmission tariff (OATT). Among other changes, Order

¹ *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on*

(continued)

No. 890 required each public utility transmission provider to have a coordinated, open, and transparent regional transmission planning process. Order No. 890 also established nine transmission planning principles, one of which addressed cost allocation for new projects.

3. The Commission acknowledges that significant work has been done in recent years to enhance regional transmission planning processes. The reforms proposed herein seek to build on this progress by improving the effectiveness of regional transmission planning and the efficiency of resulting transmission development. In formulating this proposal, the Commission has sought to balance competing interests and identify a package of reforms that, if implemented, would support the development of transmission facilities identified by the region as necessary to satisfy reliability standards, reduce congestion, and enable compliance with public policy requirements established by state or federal laws or regulations. The Commission recognizes that opinions may differ as to whether the proposal as formulated will best achieve the Commission's goals. The Commission therefore seeks comment on the reforms proposed herein and encourages commenters to identify enhancements to the reforms that could better support the efficient and effective development of transmission facilities.

4. With respect to transmission planning, the reforms proposed in this Proposed Rule would provide that: (1) local and regional transmission planning processes account for

clarification, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

transmission needs driven by public policy requirements established by state or federal laws or regulations; (2) coordination between neighboring transmission planning regions is improved with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that could address transmission needs more efficiently than separate intraregional facilities; and (3) a right of first refusal that is created by a document subject to the Commission's jurisdiction and that provides an incumbent utility with an undue advantage over nonincumbent transmission project developers is removed from that document. Neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved OATT or agreement, receive different treatment in a regional transmission planning process. Further, both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. The Commission preliminarily finds that these proposed reforms are needed to protect against unjust and unreasonable rates, terms and conditions and undue discrimination in the provision of Commission-jurisdictional services.

5. With respect to transmission cost allocation, the Commission is proposing to require public utility transmission providers to establish a closer link between cost allocation and regional transmission planning processes in which the beneficiaries of new transmission facilities are identified, as well as to establish principles that cost allocation methods must satisfy. The Commission sees these proposals as steps that would increase

the likelihood that facilities included in regional transmission plans are actually constructed. For example, establishing a closer link between transmission planning and cost allocation processes would diminish the likelihood that a transmission facility would be included in a regional transmission plan, only to later encounter cost allocation disputes that inhibit construction of that facility.

II. Background

A. Order Nos. 888 and 890

6. In Order No. 888,² issued in 1996, the Commission found that it was in the economic interest of transmission providers to deny transmission service or to offer transmission service on a basis that is inferior to that which they provide to themselves.³ Concluding that unduly discriminatory and anticompetitive practices existed in the electric industry and that, absent Commission action, such practices would increase as competitive pressures in the industry grew, the Commission in Order No. 888 and the accompanying *pro forma* OATT implemented open access to transmission facilities owned, operated, or controlled by a public utility.

² *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

³ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,682.

7. As part of those reforms, Order No. 888 and the *pro forma* OATT set forth certain minimum requirements for transmission planning. For example, the *pro forma* OATT required a public utility transmission provider to account for the needs of its network customers in its transmission planning activities on the same basis as it provides for its own needs.⁴ The *pro forma* OATT also required that new facilities be constructed to meet the service requests of long-term firm point-to-point customers.⁵ While Order No. 888-A went on to encourage utilities to engage in joint and regional transmission planning with other utilities and customers, it did not require those actions.⁶

8. In early 2007, the Commission issued Order No. 890 to remedy flaws in the *pro forma* OATT that the Commission identified based on the decade of experience since the issuance of Order No. 888. Among other things, the Commission found that *pro forma* OATT obligations related to transmission planning were insufficient to eliminate opportunities for undue discrimination in the provision of transmission service. The Commission stated that particularly in an era of increasing transmission congestion and the need for significant new transmission investment, it could not rely on the self-interest of transmission providers to expand the grid in a not unduly discriminatory manner. Among other shortcomings in the *pro forma* OATT, the Commission pointed to the lack of clear criteria regarding the transmission provider's planning obligation; the absence of a requirement that the overall transmission planning process be open to customers,

⁴ See Section 28.2 of the *pro forma* OATT.

⁵ See Sections 13.5, 15.4, & 27 of the *pro forma* OATT.

⁶ Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,311.

competitors, and state commissions; and the absence of a requirement that key assumptions and data underlying transmission plans be made available to customers.

9. In light of these findings, one of the primary goals of the reforms undertaken in Order No. 890 was to address the lack of specificity regarding how customers and other stakeholders should be treated in the transmission planning process. To remedy the potential for undue discrimination in transmission planning activities, the Commission required each public utility transmission provider to develop a transmission planning process that satisfies nine principles and to clearly describe that process in a new attachment to its OATT (Attachment K). The Order No. 890 transmission planning principles are: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.⁷

10. The transmission planning reforms adopted in Order No. 890 apply to all public utility transmission providers, including Commission-approved regional transmission organizations (RTOs) and independent system operators (ISOs). The Commission also stated that it expected all non-public utility transmission providers to participate in the planning processes required by Order No. 890. The Commission noted that reciprocity dictates that non-public utility transmission providers that take advantage of open access due to improved planning should be subject to the same requirements as jurisdictional

⁷ Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 418-601.

transmission providers.⁸ The Commission stated that a coordinated, open, and transparent regional planning process cannot succeed unless all transmission owners participate. However, the Commission did not invoke its authority under FPA section 211A, which allows the Commission to require an unregulated transmitting utility (i.e., a non-public utility transmission provider) to provide transmission services on a comparable and not unduly discriminatory or preferential basis.⁹ The Commission instead stated that if it found on the appropriate record that non-public utility transmission providers are not participating in the planning processes required by Order No. 890, then the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

11. On December 7, 2007, pursuant to Order No. 890, most public utility transmission providers and several non-public utility transmission providers submitted compliance filings that describe their proposed transmission planning processes.¹⁰ The Commission addressed these filings in a series of orders that were issued throughout 2008. Generally, the Commission accepted the compliance filings to be effective December 7, 2007, subject to further compliance filings as necessary for the proposed transmission planning

⁸ *Id.* P 441.

⁹ FPA section 211A(b) provides, in pertinent part, that “the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services – (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.” 16 U.S.C. 824j (2006).

¹⁰ A small number of transmission providers were granted extensions.

processes to satisfy the nine transmission planning principles. The Commission issued additional orders on Order No. 890 transmission planning compliance filings in the spring and summer of 2009.

12. As a result of these compliance filings, RTOs and ISOs have enhanced their regional transmission planning processes, making them more open, transparent, and inclusive. Regions of the country outside of RTO and ISO regions have also made significant strides with respect to transmission planning by working together to enhance existing, or create new, regional transmission planning processes.¹¹ These improvements to transmission planning processes have given customers and other stakeholders the opportunity to participate in the identification of regional needs and corresponding solutions, thereby facilitating the development of more efficient and effective transmission expansion plans.

B. Technical Conferences and Notice of Request for Comments on Transmission Planning and Cost Allocation

13. In several of the above-noted orders issued in 2008 and early 2009 on filings submitted to comply with the Order No. 890 transmission planning requirements, the Commission stated that it would continue to monitor implementation of these

¹¹ The regional transmission planning processes that public utility transmission providers in regions outside of RTOs and ISOs have relied on to comply with certain requirements of Order No. 890 are the North Carolina Transmission Planning Collaborative, Southeast Inter-Regional Participation Process, SERC Reliability Corporation, ReliabilityFirst Corporation, Mid-Continent Area Power Pool, Florida Reliability Coordination Council, WestConnect, ColumbiaGrid, and Northern Tier Transmission Group.

transmission planning processes. The Commission also announced its intention to convene regional technical conferences in 2009.

14. Consistent with the Commission's announcement, Commission staff in September 2009 convened three regional technical conferences in Philadelphia, Atlanta, and Phoenix, respectively. The focus of the technical conferences was to: (1) determine the progress and benefits realized by each transmission provider's transmission planning process, obtain customer and other stakeholder input, and discuss any areas that may need improvement; (2) examine whether existing transmission planning processes adequately consider needs and solutions on a regional or interconnection-wide basis to ensure adequate and reliable supplies at just and reasonable rates; and (3) explore whether existing processes are sufficient to meet emerging challenges to the transmission system, such as the development of interregional transmission facilities and the integration of large amounts of location-constrained generation. Issues discussed at the technical conferences included the effectiveness of the current transmission planning processes, the development of regional and interregional transmission plans, and the effectiveness of existing cost allocation methods used by transmission providers and alternatives to those methods.

15. Following these technical conferences, the Commission in October 2009 issued a Notice of Request for Comments.¹² The October 2009 Notice presented numerous

¹² *Federal Energy Regulatory Commission, Transmission Planning Processes Under Order No. 890; Notice of Request for Comments*; Docket No. AD09-8-000, October 8, 2009 (October 2009 Notice).

questions with respect to enhancing regional transmission planning processes and allocating the cost of transmission.

16. In response to the October 2009 Notice, the Commission received 107 initial comments and 45 reply comments.¹³ Many of these comments are discussed in greater detail later in this Proposed Rule, in the context of the Commission's proposals on specific issues.

17. In general, some commenters oppose additional Commission action at this time with respect to transmission planning. Among these commenters, some argue that existing transmission planning processes are adequate to achieve the Commission's stated goals.¹⁴ Some of these commenters highlight work already underway in their own transmission planning regions, arguing that no Commission action is needed at least in those regions. Other commenters argue that existing processes are new or are being revised and should be given time to mature before additional changes are proposed. Many of these commenters state that if the Commission chooses to act, it should do so in a manner that does not disrupt existing transmission planning processes. Some commenters that oppose Commission action on transmission planning at this time state that it is important to maintain what they describe as a "bottom-up" approach to transmission planning, in which regional transmission planning is based on transmission

¹³ See Appendix A for a list of the commenters and their abbreviated names.

¹⁴ E.g., Dominion, Large Public Power Council, Midwest ISO, New York PSC, Northern Tier Transmission Group, and WECC.

planning conducted by the individual transmission-owning utilities in a transmission planning region.¹⁵

18. Many other commenters support additional Commission action on transmission planning at this time.¹⁶ These commenters offer a wide range of views on why and how the planning process should be improved. Although these commenters express diverse views, there appears to be a consensus among those supporting action that the Commission should—at a minimum—provide guidance about planning for large, interregional transmission projects.

19. Many commenters that support Commission action on transmission planning raise issues related to the procedural characteristics or geographic scope of existing transmission planning processes. Some commenters contend that the Order No. 890 transmission planning principles should be extended to support interregional coordination, while others argue that additional planning principles are necessary to ensure the effectiveness of transmission planning processes. Some commenters suggest that the type of “bottom-up” transmission planning described above is insufficient,¹⁷ and other commenters advocate changes such as establishing a regional or interconnection-wide planning coordinator.¹⁸ A few commenters suggest that the Commission add to the

¹⁵ *E.g.*, Ohio Commission, PPL, Southern Companies, and WECC.

¹⁶ *E.g.*, American Transmission, Californians for Renewable Energy, Dayton Power and Light, E.ON, LS Power, NRG, Pioneer Transmission, San Diego Gas & Electric, and Transmission Access Policy Study Group.

¹⁷ *E.g.*, Calvin Daniels (commenting as an individual).

¹⁸ *E.g.*, AEP.

OATT a *pro forma* seams agreement that includes joint collaborative planning and cost allocation across planning regions.¹⁹ Still other commenters support changes to transmission planning processes, but caution against adopting a one-size-fits-all or an interconnectionwide approach.²⁰

20. Other commenters that support Commission action on transmission planning argue that some existing transmission planning processes provide an incumbent transmission owner with an unfair advantage over merchant and independent transmission project developers, such as by providing an incumbent transmission owner with a right of first refusal²¹ to construct a transmission facility that is included in a regional transmission plan and meets certain other criteria.²² These commenters argue that such practices discourage other, merchant and independent transmission developers'²³ participation in the transmission planning process and present a significant barrier to transmission

¹⁹ E.g., Midwest ISO Transmission Owners, National Rural Electric Coops, and SPP.

²⁰ E.g., Pacific Gas and Electric and Transmission Agency of Northern California.

²¹ A right of first refusal is defined, for the purposes of this proposed rulemaking, as the right of an incumbent transmission owner to construct, own, and propose cost recovery for any new transmission project that is: (1) located within its service territory; and (2) approved for inclusion in a transmission plan developed through the Order No. 890 planning process.

²² E.g., AWEA, EPSA, LS Power, and Transmission Dependent Utility Systems.

²³ Merchant transmission projects are defined as those for which the costs of constructing the proposed transmission facilities will be recovered through negotiated rates instead of cost-based rates. For purposes of this proposed rulemaking, an incumbent transmission developer is an entity that develops a project within its own service territory. We note that a transmission owner that proposes a project outside of its own service territory is not considered an incumbent for purposes of that project.

investment. Other commenters state that projects proposed by merchant and independent transmission project developers need to be included fully in regional transmission planning processes on the same basis as other projects.²⁴

21. Still other commenters that support Commission action on transmission planning express concern that current transmission planning processes do not adequately assess all of the potential benefits associated with transmission project proposals.²⁵ Some of these commenters state that more attention needs to be devoted to analyzing the benefits associated with economic-based projects and incorporating such projects into regional transmission plans.²⁶ PJM states that generic planning principles are needed to deal with the various social, environmental and economic impacts of regional transmission projects. In addition, several commenters recommend that the Commission incorporate state and federal public policy objectives into the transmission planning process,²⁷ noting, for example, that doing so could facilitate cost-effective achievement of those objectives.

²⁴ *E.g.*, Allegheny Companies, AEP, Californians for Renewable Energy, Delaware Municipal and Southwestern Electric, E.ON Climate & Renewables North America, Great River Energy, Sun Flower and Mid-Kansas, National Nuclear Security Administration Service Center, Organization of MISO States, and Transmission Agency of Northern California.

²⁵ *E.g.*, AEP, AWEA, Baltimore Gas and Electric, Energy Future Coalition, Exelon, Green Energy Express, ITC Holdings, MidAmerican, National Audubon Society, *et al.*, NextEra, and Public Interest Organizations & Renewable Energy Groups.

²⁶ *E.g.*, MidAmerican and Old Dominion.

²⁷ *E.g.*, AWEA, Baltimore Gas and Electric, Exelon, Eastern PJM Governors, The Brattle Group, ITC Holdings, LS Power, National Audubon Society, *et al.*, National Grid, NextEra, Old Dominion, PJM, Public Interest Organizations & Renewable Energy Groups, Renewable Energy Systems Americas, and Trans-Elect.

Commenters also recommend that the Commission provide for flexibility so that each transmission planning region could determine which resources it would use to fulfill these public policy objectives.²⁸

22. The Commission's questions in the October 2009 Notice with respect to allocating the cost of transmission also drew wide-ranging responses. For example, some commenters express concern that the lack of a link between transmission planning and cost allocation procedures may unnecessarily block or delay needed projects.²⁹ Other commenters support establishing a generic cost allocation method as a backstop that would apply when parties or transmission planning regions cannot agree on a cost allocation method.³⁰

23. Some commenters indicate that the Commission should provide more detailed guidelines or principles for allocating the costs of new transmission facilities.³¹ These commenters generally agree that those who share in the benefits of transmission facilities should be responsible for their costs. However, there is not a consensus on how this principle should be implemented; what benefits should be considered for purposes of cost allocation, or how to determine who is a beneficiary.

²⁸ *E.g.*, Consolidated Edison, *et al.*

²⁹ *E.g.*, ITC Holdings, AEP, American Transmission, Green Energy Express, and WIRES.

³⁰ *E.g.*, American Transmission; National Grid; and NEPOOL Participants.

³¹ *E.g.*, APPA, Green Energy Express, ITC Holdings, NEPOOL Participants, NextEra, Ohio Commission, Solar Energy Industries, and Transmission Access Policy Study Group.

24. Some commenters urge the Commission to avoid rushing to a one-size-fits-all approach to determining beneficiaries of transmission projects, due to the varying nature of projects and benefits.³² Others express the view that it is difficult to quantify certain benefits that they consider relevant, such as carbon emission reduction, integration of renewable generation, or the most efficient use of existing rights-of-way.³³ Other commenters suggest that there are ways to factor difficult to quantify benefits into the planning process such that they are adequately considered.³⁴

C. Additional Developments Since Issuance of Order No. 890

25. Other developments with important implications for transmission planning have occurred amid the above-noted Order No. 890 compliance efforts on transmission planning and as the Commission gathered information through the technical conferences and the October 2009 Notice discussed above.

26. For example, in February 2009, Congress enacted the American Recovery and Reinvestment Act (ARRA), which provided \$80 million for the U.S. Department of Energy (DOE), in coordination with the Commission, to support the development of interconnection-based transmission plans for the Eastern, Western, and Texas interconnections. In seeking applications for use of those funds, DOE described the

³² *E.g.*, APPA, Bonneville, California ISO, ColumbiaGrid, Consolidated Edison, *et al.*, Dayton Power and Light, EEI, Entergy, Midwest ISO, Southern Companies.

³³ *E.g.*, California ISO, Electricity Consumers Resource Council, MidAmerican, National Grid.

³⁴ *E.g.*, AWEA, Energy Future Coalition, Entergy, Exelon, ITC Holdings, Integrys, *et al.*

initiative as intended to: (1) improve coordination between electric industry participants and states on the regional, interregional, and interconnection-wide levels with regard to long-term electricity policy and planning; (2) provide better quality information for industry planners and state and federal policymakers and regulators, including a portfolio of potential future supply scenarios and their corresponding transmission requirements; (3) increase awareness of required long-term transmission investments under various scenarios, which may encourage parties to resolve cost allocation and siting issues; and (4) facilitate and accelerate development of renewable or other low-carbon generation resources.³⁵

27. In December 2009, DOE announced award selections for much of this ARRA funding. In each interconnection, applicants awarded funds under what DOE defined as Topic A are responsible for conducting interconnection-level analysis and transmission planning. Applicants awarded funds under Topic B are to facilitate greater cooperation among states and stakeholders within each interconnection to guide the analyses and planning performed under Topic A.³⁶ Broad participation in sessions to date related to this initiative suggest that the availability of federal funds to pursue these goals has increased awareness of the potential for greater coordination among regions in transmission planning.

³⁵ Department of Energy, *Recovery Act- Resource Assessment and Interconnection-Level Transmission Analysis and Planning Funding Opportunity Announcement*, at 5-6 (June 15, 2009).

³⁶ *Id.* at 4-8.

28. DOE has also been involved in the development of several recent reports that may have implications for transmission planning. In its 2008 report, *20% Wind Energy by 2030*, DOE concludes that “[s]ignificant expansion of the transmission grid will be required under any future electric industry scenario. Expanded transmission will increase reliability, reduce costly congestion and line losses, and supply access to low-cost remote resources, including renewables.”³⁷

29. Similarly, in its 2009 report, *Keeping the Lights On in a New World*, the DOE Electricity Advisory Committee concluded that expanding and strengthening the nation’s transmission infrastructure is becoming increasingly important for two reasons: “First, increasing transmission capability will help ensure a reliable electric supply and provide greater access to economically priced power. Second, the growth in renewable energy development, stimulated in part by state-adopted renewable portfolio standards (RPS) and the possibility of a national RPS, will require significant new transmission to bring these resources, which are often remotely located, to consumer load centers.”³⁸

30. The number of states that have adopted renewable portfolio standard measures, as well as the target levels set in those measures, has continued to increase. Some 30 states and the District of Columbia have now adopted renewable portfolio standard measures.

³⁷ Department of Energy, *20% Wind Energy by 2030*, at 93 (July 2008).

³⁸ Electricity Advisory Committee, *Keeping the Lights On in a New World*, at 45 (Jan. 2009). The Electricity Advisory Committee was formed to provide advice to DOE in implementing the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, and in modernizing the nation’s electricity delivery infrastructure. The Electricity Advisory Committee includes representatives from industry, academia, and state government.

These measures typically require that a certain percentage of energy sales (MWh) or installed capacity (MW) come from renewable energy resources, with the target level and qualifying resources varying among the renewable portfolio standard measures.

31. In its role as the Commission-designated Electric Reliability Organization, the North American Electric Reliability Corporation (NERC) concluded that significant transmission expansion will be needed to comply with renewable mandates. Even in the absence of a national renewable portfolio standard, NERC has stated that “an analysis of the past 14 years shows that the siting and construction of transmission lines will need to significantly accelerate to maintain reliability over the coming years.”³⁹ In its 2009 assessment of transmission needs, NERC found that if a national renewable portfolio standard of 15 percent were adopted, an additional 40,000 miles of transmission lines would be needed and “transmission would be a key component to accommodating new resources, linking geographically remote generation to demand centers.”⁴⁰

III. The Need for Reform

32. The Commission notes that transmission planning processes, particularly at the regional level, have seen substantial improvement through compliance with Order No. 890. As noted above, these improvements have increased opportunities for customers and other stakeholders to participate in the identification of regional needs and

³⁹ North American Electric Reliability Corporation, *2009 Long-Term Reliability Assessment: 2009-2018*, October 2009, at 29.

⁴⁰ North American Electric Reliability Corporation, *2009 Scenario Reliability Assessment: 2009-2018*, October 2009, at 9.

corresponding solutions, facilitating the development of more efficient and effective transmission plans. The Commission believes that the expanded cooperation and collaboration that is now occurring in transmission planning both among transmission providers and between transmission providers and their stakeholders is to be commended.

33. Although Order No. 890 became effective just a few years ago, there have been significant changes in the nation's electric power industry in those few years that require the Commission to consider additional reforms to transmission planning and cost allocation to reflect these new circumstances. These changes have been widely recognized within the industry.⁴¹ Our intention in this Proposed Rule is not to disrupt the progress that is already being made with respect to transmission planning and investment in transmission infrastructure, but rather to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and thereby ensure that Commission-

⁴¹ For example, a trend of increased investment in the country's transmission infrastructure has emerged in recent years. EEI attributes that trend to, among other factors, recognition of the reliability and other developments discussed above, as well as enactment of the Energy Policy Act of 2005 and the Commission's implementation of its new transmission pricing policies. EEI has also observed that even amid this trend of increased investment in transmission infrastructure, transmission projects that would be located in more than one state "face significant challenges for siting, permitting, cost allocation and cost recovery." *Transmission Projects: At a Glance*, Prepared by Edison Electric Institute with assistance from Navigant Consulting, Inc., February 2010, at iii-iv. EEI has also stated that "[t]hese challenges must be resolved to facilitate the movement of large quantities of renewable energy." *Transmission Projects Supporting Renewable Resources*, Prepared by Edison Electric Institute, February 2009, at iv.

jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

34. The siting, permitting, and cost allocation of transmission facilities face significant challenges. These challenges may be present whether an interstate transmission project is proposed to be located within a single region for which transmission planning is conducted in accordance with Order No. 890 (i.e., an intraregional transmission facility) or is instead proposed to be located in more than one such transmission planning region (i.e., an interregional transmission facility). The failure to address these challenges also can lead to increases in congestion costs. For example, PJM stated recently that prices for new generating capacity in the eastern part of its transmission planning region have increased due to constraints on its transmission system. Observing that capacity prices in the western portion of PJM were \$27.73 per megawatt-day, while capacity prices in the transmission-constrained areas of PJM were between \$226.15 and \$247.14 per megawatt-day, PJM noted that "the great difference in prices for the eastern portion of PJM compared with elsewhere shows the need for increased transmission line capacity into the region. Transmission line additions and upgrades would reduce capacity price differences."⁴²

35. In light of the comments and developments discussed above, one deficiency that has arisen is the lack of a requirement for a regional transmission plan, without which the construction of new transmission facilities could be inhibited. Additionally, in the

⁴² PJM Interchange, News Release, May 14, 2010.

absence of such a requirement, the facilities best suited to meet the needs of a particular region may not be identified.

36. Another deficiency that has arisen since the issuance of Order No. 890 involves transmission needs driven by public policy requirements established by state or federal laws or regulations. For example, state policies to promote increased reliance on renewable energy resources, such as the renewable portfolio standard measures discussed above, accentuate the need for transmission to deliver electricity from location-constrained renewable energy resources to load centers. Other state policies, such as goals for use of energy efficiency or demand response, may lower load forecasts within a given load zone and thereby affect transmission planning determinations. In addition, states may adopt economic development policies associated with meeting energy needs that may be relevant to assumptions made in a transmission planning process. Future public policy requirements established by federal laws or regulations also could have a significant effect on transmission planning.

37. However, existing transmission planning processes generally were not designed to account for, and do not explicitly consider, these types of public policy requirements established by state or federal laws or regulations. Indeed, some comments submitted in response to the October 2009 Notice indicate that current transmission planning processes may not permit consideration of public policy requirements within regional transmission plans.⁴³ As discussed in greater detail below, the Commission preliminarily

⁴³ *E.g.*, Baltimore Gas and Electric, Eastern PJM Governors, ITC Holdings, LS
(continued)

finds that the failure to account explicitly for such public policy requirements in the transmission planning process may result in undue discrimination and rates, terms, and conditions of service that are not just and reasonable.

38. A third deficiency involves obstacles to nonincumbent transmission project developers' participation in regional transmission planning processes. The Commission in recent years has seen increasing interest in transmission investment among these developers. Such interest, however, often has been coupled with expressions of concern about the treatment of merchant and independent transmission project developers in relevant transmission planning processes.⁴⁴ Many commenters raised similar concerns in response to the October 2009 Notice, describing what they see as remaining opportunities for undue discrimination against nonincumbent transmission project developers in transmission planning processes. Such undue discrimination could discourage these developers from presenting projects in regional transmission planning processes, which, in turn, could inhibit development of beneficial transmission facilities.

39. A fourth deficiency involves the relative lack of coordination between transmission planning regions. In Order No. 890, the Commission found that when transmission providers engage in regional transmission planning, they may identify solutions to regional needs that are more efficient than those that would have been

Power, National Grid, Old Dominion, PJM, and Trans-Elect.

⁴⁴ See, e.g., *Green Energy Express LLC*, 129 FERC ¶ 61,165 (2009); *Western Grid Dev., LLC*, 130 FERC ¶ 61,056 (2010); *Pioneer Transmission LLC*, 126 FERC ¶ 61,281 (2009).

identified if needs and potential solutions were evaluated only independently by each individual transmission provider.⁴⁵ Similarly, in the absence of coordination between transmission planning regions, transmission providers may not identify more efficient and cost-effective solutions to the individual needs identified in their respective utility-level and regional transmission planning processes, potentially including interregional transmission projects. In the few years since the issuance of Order No. 890, interest in multiregional facilities has grown significantly.⁴⁶ The October 2009 Notice observed that the lack of coordinated planning over the seams of current transmission planning regions could be needlessly increasing costs for customers of individual transmission providers. Accordingly, the Order No. 890 transmission planning requirements may not be just and reasonable in that they may not be sufficient to address the need for greater coordination in interregional transmission planning.

40. Finally, we preliminarily conclude that existing methods for allocating the costs of new transmission may not be just and reasonable because they may inhibit the development of efficient, cost-effective transmission facilities necessary to produce just and reasonable rates. While challenges associated with allocating the cost of transmission are not new, those challenges appear to have become more acute as the need

⁴⁵ “The coordination of planning on a regional basis will also increase efficiency through the coordination of transmission upgrades that have region-wide benefits, as opposed to pursuing transmission expansion on a piecemeal basis.” Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 524.

⁴⁶ See, e.g., *Pioneer Transmission LLC*, 126 FERC ¶ 61,281 (2009); *Green Power Express*, 127 FERC ¶ 61,031 (2009).

for transmission infrastructure has grown. For example, the expansion of regional power markets and the increasing adoption of state policies to promote increased reliance on renewable energy resources have led to a growing need for regional or interregional transmission facilities. Meanwhile, determining the benefits of adding transmission infrastructure to the grid is a complex process, particularly for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. In such circumstances, any individual beneficiary of a project has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development.

41. Moreover, as stated in the October 2009 Notice, constructing new transmission facilities requires a significant amount of capital. Therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. However, there are few rate structures in place today that provide for the allocation and recovery of costs for projects that are proposed to be located either within a transmission planning region that is outside of an RTO or ISO, or in more than one transmission planning region. The lack of such rate structures creates significant risk for transmission project developers that they will have no identified group of customers from which to recover the cost of their investment.

42. Therefore, the Commission proposes to reform transmission planning and cost allocation processes as described in the following sections of this Proposed Rule.

Although focused on discrete aspects of the transmission planning and cost allocation processes, these reforms are integrally related and should be understood as a package.

With these related reforms, more transmission projects would be considered in the transmission planning process on an equitable basis, and more facilities that are included in transmission plans are likely to move forward to construction.

43. The Commission recognizes that many of the existing regional transmission planning processes are comprised of both public utility and non-public utility transmission providers. Consistent with the approach taken in Order No. 890,⁴⁷ the Commission expects all public utility and non-public utility transmission providers to participate in the regional transmission planning and cost allocation processes proposed by this Proposed Rule. Reciprocity dictates that non-public utility transmission providers that take advantage of open access, including improved regional transmission planning and cost allocation, should be subject to the same requirements as public utility transmission providers. We are encouraged, based on the efforts that followed Order No. 890, that both public utility and non-public utility transmission providers collaborate in a number of regional transmission planning processes. We therefore do not believe it is necessary at this time to invoke our authority under FPA section 211A, which allows us to require non-public utility transmission providers to provide transmission services on a comparable and not unduly discriminatory or preferential basis. However, if the Commission finds on the appropriate record that non-public utility transmission providers are not participating in the regional transmission planning and cost allocation processes

⁴⁷ Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 441.

proposed in this Proposed Rule, the Commission may exercise its authority under FPA section 211A on a case-by-case basis.

IV. Proposed Reforms: Transmission Planning

44. Transmission planning is a critical component of the provision of transmission service in interstate commerce. Among other purposes, transmission planning is the means by which the transmission needs of a given area and the facilities that are best suited to meet those needs are identified. Based on the comments received in response to the October 2009 Notice and the other developments and considerations discussed above, the Commission believes that further steps with respect to transmission planning may be necessary to protect against unjust and unreasonable rates, terms and conditions and undue discrimination in the provision of Commission-jurisdictional services.

A. Participation in the Regional Planning Process

45. In Order No. 890, the Commission adopted a regional participation principle as a necessary component of a public utility transmission provider's transmission planning process. To meet that principle, the Commission required that each public utility transmission provider coordinate with interconnected systems to: (1) share system plans to ensure that the plans are simultaneously feasible and otherwise use consistent assumptions and data; and (2) identify system enhancements that could relieve congestion or integrate new resources.⁴⁸ This requirement for coordination at the regional level can be contrasted with the separate requirement in Order No. 890 that each

⁴⁸ Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

public utility transmission provider use an open and transparent process to develop a transmission plan for its own control area.⁴⁹ In other words, by adopting the regional participation principle, the Commission did not require development of a comprehensive regional transmission plan.

46. The Commission explained that in complying with the regional participation principle, the specific features of a public utility transmission provider's regional transmission planning process should take account of and accommodate, where appropriate, existing institutions, as well as historical practices and the physical characteristics of the region.⁵⁰ The Commission recognized that regional transmission planning already occurs, for example, as part of the NERC Regional Entity planning process.⁵¹ The Commission urged public utility transmission providers to closely examine whether improvements in these regional transmission planning processes could be implemented to satisfy the requirements of Order No. 890 imposed on individual transmission providers.⁵²

47. The Commission also stated that to satisfy the regional participation principle, an existing transmission planning process must be open and inclusive and address both reliability and economic considerations.⁵³ The Commission required each public utility

⁴⁹ *Id.* P 494, 523.

⁵⁰ *Id.* P 524.

⁵¹ *Id.* P 528.

⁵² *Id.* P 526.

⁵³ *Id.* P 528.

transmission provider to participate in a transmission planning process that facilitates regional participation and that is open to all interested customers and stakeholders.⁵⁴

However, the Commission did not require each regional transmission planning process to comply with each of the nine transmission planning principles established in Order No. 890.⁵⁵

48. On compliance with these Order No. 890 requirements, many public utility transmission providers relied on existing regional entities and transmission planning processes, modified as necessary, to comply with the regional participation principle.⁵⁶

49. Since the issuance of Order No. 890, it has become apparent to the Commission that Order No. 890's regional participation principle may not be sufficient, in and of itself, to ensure an open, transparent, inclusive, and comprehensive regional transmission planning process. Without such a process, each transmission provider will not have information needed to assess proposed projects and determine which project or group of projects could satisfy local and regional needs more efficiently and cost-effectively. As a result, the rates, terms and conditions of transmission services may not be just and

⁵⁴ Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 226.

⁵⁵ See, e.g., *Entergy Services, Inc.*, 124 FERC ¶ 61,268, at P 104 (2008).

⁵⁶ As we note above, the regional transmission planning processes that public utility transmission providers in regions outside of RTOs and ISOs have relied on to comply with certain requirements of Order No. 890 are North Carolina Transmission Planning Collaborative, Southeast Inter-Regional Participation Process, SERC Reliability Corporation, ReliabilityFirst Corporation, Mid-Continent Area Power Pool, Florida Reliability Coordination Council, WestConnect, ColumbiaGrid, and Northern Tier Transmission Group.

reasonable. For example, greater regional coordination in transmission planning would expand opportunities for transmission providers, their transmission customers, and other stakeholders to identify and implement regional solutions to local and regional needs that are more cost-effective than those proposed in the transmission planning process of individual transmission providers. In addition, more effective regional transmission planning could better facilitate the integration of location-constrained renewable energy resources, which may be needed to fulfill public policy requirements such as the renewable portfolio standards adopted by many states.

50. Given this concern, we propose to require that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and that meets the following transmission planning principles established in Order No. 890: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; and (7) economic planning studies.⁵⁷

51. More specifically, we propose to require that each regional transmission planning process consider and evaluate transmission facilities and other non-transmission solutions that may be proposed and develop a regional transmission plan that identifies the transmission facilities that cost-effectively meet the needs of transmission providers, their

⁵⁷ This proposal does not include the regional participation principle and cost allocation for new projects principle of Order No. 890 because we address interregional coordination in transmission planning and cost allocation for transmission facilities included in a regional transmission plan elsewhere in this Proposed Rule.

transmission customers, and other stakeholders.⁵⁸ When an individual transmission provider engages in local transmission planning, it considers and evaluates transmission facilities and non-transmission solutions that are proposed and then develops a local transmission plan that identifies what transmission facilities are needed to meet the needs of its native load (if any), transmission customers, and other stakeholders. Likewise, the regional transmission planning process would consider and evaluate transmission facilities and non-transmission solutions that are proposed and develop a regional transmission plan that identifies what transmission facilities are needed to meet the needs of transmission customers and other stakeholders in the region.⁵⁹

52. In addition, because of the increased importance of regional transmission planning that is designed to produce a regional transmission plan, transmission customers and other stakeholders must be provided with an opportunity to participate meaningfully in that process. Therefore, we propose to apply the above-noted Order No. 890

⁵⁸ When evaluating potential solutions to identified needs, transmission providers must evaluate proposals for transmission, generation, and demand resources against one another based on criteria set forth in their tariffs. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 494-95; Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 216. The Commission also has recognized that in appropriate circumstances alternative technologies may be eligible for treatment as transmission for ratemaking purposes. *Western Grid*, 130 FERC ¶ 61,056 (2010).

⁵⁹ As noted in Order No. 890, the planning obligations proposed here do not address or dictate which investments identified in a transmission plan should be undertaken by transmission providers. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 438. As also noted in Order No. 890, the ultimate responsibility for transmission planning remains with transmission providers. With that said, the Commission fully intends that the transmission planning processes provide for the timely and meaningful input and participation of customers into the development of transmission plans. *Id.* P 454.

transmission planning process. As defined in Order No. 890, these high priority studies are intended to identify solutions that could relieve transmission congestion or integrate new resources and loads, including upgrades to integrate new resources or loads on an aggregated or regional basis.⁶⁴

58. In Order No. 890, the Commission also required each public utility transmission provider to coordinate its transmission planning activities with the relevant state and local regulatory authorities that choose to participate in the transmission planning process and stated its expectation that “all transmission providers will respect states’ concerns.”⁶⁵ As such, state and local regulatory authorities may fully participate in the existing Order No. 890 transmission planning process and identify, among other issues, public policy requirements established by state or federal laws or regulations that they see as relevant to transmission needs. However, when choosing whether to include a proposed transmission project in its local or regional transmission plan, a public utility transmission provider has no explicit obligation under Order No. 890 or the *pro forma* OATT to evaluate the project based on its potential to facilitate the achievement of public policy requirements established by state or federal laws or regulations.

59. The October 2009 Notice observed that some areas are struggling with how to adequately address transmission expansion necessary to, for example, integrate renewable generation resources into the transmission system. The October 2009 Notice

⁶⁴ Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 547-48.

⁶⁵ *Id.* P 574.

attributed these difficulties in part to the fact that planning transmission facilities necessary to meet state resource requirements, such as the renewable portfolio standard measures discussed above, must be integrated with existing transmission planning processes that are based on metrics or tariff provisions focused on reliability or in some cases production cost savings.⁶⁶ Drawing on these observations, the October 2009 Notice sought comment as to whether reliability impact studies are properly aligned with evaluations of economic-based projects or projects proposed to satisfy renewable energy standards. To the extent that assessments of various possible project benefits are not properly aligned, the October 2009 Notice sought comment as to how reliability assessments, economic evaluations and assessments of a project's ability to meet public policy goals could be aligned to better identify options that meet all of these regional needs.⁶⁷

60. The Commission received a number of comments on these issues, expressing a range of opinions. Several commenters argue that the existing transmission planning and stakeholder processes properly align reliability impact studies with evaluations of other projects designed to meet economic-based or public policy requirements.⁶⁸ Other

⁶⁶ October 2009 Notice at 3.

⁶⁷ *Id.* at 4.

⁶⁸ *E.g.*, Dominion, Entergy, Large Public Power Council, Midwest ISO, New York PSC, Northern Tier Transmission Group, Southern Companies, WestConnect Planning Parties, and WECC. In addition, PSEG Companies state that while it is true that reliability impact studies are performed independently of economic planning, such a distinction is appropriate because ensuring reliability is the primary objective of the planning process.

commenters suggest that it would be inappropriate for the Commission to require that renewable energy standards be incorporated into the transmission planning process.⁶⁹ For example, Public Power Council contends that the Commission lacks jurisdiction to require that the resources necessary to comply with state renewable energy standards are accounted for in the transmission planning process, as such standards are state-level policies.⁷⁰

61. In addition, several commenters recommend that the Commission incorporate public policy objectives into the transmission planning process.⁷¹ For example, PJM argues that “additional guidance from the Commission is needed if public policy imperatives such as aggressive integration of renewable resources are to be met.”⁷² PJM states that while ensuring system reliability should remain the primary goal of the transmission planning process, providing for incorporation of public policy objectives, where applicable, could facilitate cost-effective achievement of those objectives. In particular, PJM suggests that the Commission move beyond a strict application of “bright line” criteria currently used for reliability and economic projects and allow transmission

⁶⁹ *E.g.*, Massachusetts Departments and Public Power Council.

⁷⁰ Massachusetts Departments share a similar concern.

⁷¹ *E.g.*, AWEA, Baltimore Gas and Electric, Public Interest Organizations & Renewable Energy Groups, Exelon, Eastern PJM Governors, ITC Holdings, LS Power, National Grid, NextEra, Old Dominion, PJM, Renewable Energy Systems Americas, Trans-Elect, and The Brattle Group.

⁷² PJM Order No. 890 Technical Conference Comments, *op. cit.* at 6.

providers more flexibility to take into account the multiple reliability, economic, or public policy-based benefits a single project may be able to provide.⁷³

62. Other commenters propose various approaches to incorporating public policy objectives into the transmission planning process. Some of these commenters argue that if the goal of the transmission planning process is to allow load-serving entities to satisfy their resource needs, such needs could include resources required to comply with state and federal public policy objectives.⁷⁴ Still other commenters recommend that the Commission provide flexibility in the transmission planning process so that each region can determine which resources it will use to fulfill any applicable public policy objectives.⁷⁵

63. To ensure that each public utility transmission provider's transmission planning process supports rates, terms, and conditions of transmission service in interstate commerce that are just and reasonable and not unduly discriminatory or preferential, the Commission preliminarily finds that transmission needs driven by public policy requirements established by state or federal laws or regulations should be taken into account in the transmission planning process. Indeed, consideration of such public policy requirements raises issues similar to those raised in the Commission's discussion in Order

⁷³ Citing, *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,265 (2007) (directing PJM to adopt a formulaic approach to applying metrics used to choose economic projects).

⁷⁴ E.g., APPA and Bay Area Municipal Transmission Group.

⁷⁵ E.g., Consolidated Edison, et al.

No. 890 of the Economic Planning Studies principle.⁷⁶ When conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving native load, but also consider how to enable compliance with relevant public policy requirements established by state or federal laws or regulations in a cost-effective manner. Therefore, we propose to find that, to avoid acting in an unduly discriminatory manner, a public utility transmission provider must consider these same needs on behalf of all of its customers. In addition, providing for incorporation of public policy requirements established by state or federal laws or regulations in transmission planning processes, where applicable, could facilitate cost-effective achievement of those requirements.

64. To address these issues, we propose to revise the requirements established in Order No. 890 with respect to local and regional transmission planning processes.⁷⁷ Specifically, we propose to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide

⁷⁶ In Order No. 890, the Commission intended the economic planning studies principle to be sufficiently broad to identify solutions that could relieve transmission congestion or integrate new resources and loads, including upgrades to integrate new resources and loads on an aggregated or regional basis. The Commission recognizes that its statements with respect to the economic planning studies principle may have contributed to confusion as to whether public policy requirements may be considered in the transmission planning process.

⁷⁷ By "local" transmission planning process, we mean the transmission planning process that a public utility transmission provider performs for its individual service territory or footprint pursuant to the requirements of Order No. 890.

for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs. After consulting with stakeholders, a public utility transmission provider may include in the transmission planning process additional public policy objectives not specifically required by state or federal laws or regulations. This proposed requirement would be a supplement to, and would not replace, any existing requirements with respect to consideration of reliability needs and application of the economic studies principle in the transmission planning process.

65. The Commission does not propose to identify the public policy requirements established by state or federal laws or regulations that must be considered in individual local and regional transmission planning processes. Instead, we propose to require each public utility transmission provider to coordinate with its customers and other stakeholders to identify public policy requirements established by state or federal laws or regulations that are appropriate to include in its local and regional transmission planning processes.

66. We propose to require each public utility transmission provider to specify in its OATT the procedures and mechanisms in its local and regional transmission planning processes for evaluating transmission projects proposed to achieve public policy requirements established by state or federal laws or regulations. If a public utility transmission provider believes that its existing transmission planning processes satisfy these requirements, then it must make that demonstration in its compliance filing.

67. This proposed requirement is intended to clarify the objectives that would be considered in local and regional transmission planning processes. As we stated in Order

No. 890, we believe that the transparency provided under open transmission planning processes can provide useful information that would help states to coordinate transmission and generation siting decisions, allow consideration of regional resource adequacy requirements, facilitate consideration of demand response and load management programs at the state level, and address other factors states wish to consider.

68. Another benefit of this proposed requirement to consider public policy requirements established by state or federal laws or regulations within the transmission planning process is that adherence with this proposed requirement may eventually increase the proportion of transmission network investment that is constructed pursuant to proactive transmission planning processes, thereby reducing the proportion of network upgrades that would otherwise be triggered by individual generator interconnection requests, which can be time consuming and inefficient. If more of the transmission network were expanded under the type of regional transmission planning process described above, then the network upgrades triggered by interconnection requests should be less significant in size and cost than they have been in the past and the associated differences in cost allocation provisions may become less significant as well.

69. This proposed requirement is not intended in any way to infringe upon state authority with respect to integrated resource planning.⁷⁸ In addition, to the extent that a public utility transmission provider has an obligation to comply with public policy requirements established by state or federal laws or regulations, such as the state

⁷⁸ Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 479, n.274.

renewable portfolio standard measures discussed above, this proposed requirement is not intended to convert a failure to satisfy that obligation into a violation of its OATT. In other words, while a public utility transmission provider would be required to identify and consider public policy requirements established by state or federal laws or regulations in its local and regional transmission planning processes, this proposed requirement would not establish an independent obligation to satisfy those requirements.

70. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule. In particular, we seek comment as to whether public policy requirements established by state or federal laws or regulations should be considered in the transmission planning process. Further, we seek comment on how planning criteria based on public policy requirements should be formulated, including whether it is more appropriate to use flexible criteria instead of "bright line" metrics when determining which projects are to be included in the regional transmission plan, whether the use of flexible criteria would provide undue discretion as to whether a project is included in a regional transmission plan, and whether the use of "bright line" metrics may inappropriately result in alternating inclusion and exclusion of a single project over successive planning cycles and therefore create inappropriate disruptions in long-term transmission planning.

C. Opportunities for Undue Discrimination against Nonincumbent Transmission Developers

1. Nonincumbent Transmission Developer Participation in the Transmission Planning Process

71. As discussed above, Order No. 890 sought to reduce opportunities for undue discrimination and preference in the provision of transmission service. With regard to the transmission planning process, the Commission established nine transmission planning principles to prevent undue discrimination. However, Order No. 890 did not specifically address the potential for undue preference to incumbent utilities over nonincumbent transmission developers through practices applied within transmission planning processes.

72. The October 2009 Notice observed that in some areas, when a nonincumbent transmission developer participates in the transmission planning process, it may lose the opportunity to construct its proposed project to the incumbent transmission owner if that owner has a right of first refusal to construct any transmission facility in its service territory. The October 2009 Notice also observed that in some areas, merchant transmission developers choose to plan proposed facilities outside of the transmission providers' planning processes.⁷⁹

73. The October 2009 Notice posed several questions relating to merchant and independent transmission developers' participation in the regional transmission planning process. The October 2009 Notice sought comment on how projects proposed by

⁷⁹ October 2009 Notice at 3.

merchant or independent transmission developers should be treated in the regional transmission planning process. The October 2009 Notice also asked whether these types of developers should be required to participate in the regional transmission planning process and, if so, at what point they should be required to engage in that process. In addition, the October 2009 Notice asked whether the right of first refusal for incumbent transmission owners unreasonably impedes the development of merchant and independent transmission and, if so, how that impediment could be addressed. Finally, the October 2009 Notice asked whether there are barriers to merchant and independent transmission developers' participation in the regional transmission planning process other than rights of first refusal.⁸⁰

74. These questions generated extensive comments. For example, many commenters argue that a project proposed by a merchant or independent transmission developer should be treated on the same basis as all other proposed projects.⁸¹ Also, a number of commenters assert that merchant and independent developers should be required to participate in the transmission planning process.⁸² For example, Southern Companies

⁸⁰ *Id.* at 4.

⁸¹ *E.g.*, Allegheny Companies, AEP, Californians for Renewable Energy, Delaware Municipal and Southwestern Electric, E.ON Climate & Renewables North America, Great River Energy, Sun Flower and Mid-Kansas, National Nuclear Security Administration Service Center, Organization of MISO States, and Transmission Agency of Northern California.

⁸² *E.g.*, APPA, Californians for Renewable Energy, Delaware Municipal and Southwestern Electric, Dominion, Exelon, Integrys, Old Dominion, Sun Flower and Mid-Kansas, Large Public Power Council, Midwest ISO, National Nuclear Security Administration Service Center, National Rural Electric Coops, New England States'

(continued)

asserts that it would be discriminatory if the Commission did not require merchant and independent developers to participate in the transmission planning process, as jurisdictional and non-jurisdictional transmission providers are required to do.

75. Other commenters state that merchant and independent developers should not be treated similarly or required to participate in the transmission planning process. For example, Chinook and Zephyr and ITC Holdings state that because the business model of merchant and independent transmission developers is different from that of vertically-integrated utilities, different transmission planning requirements are appropriate for them. Chinook and Zephyr also argue that regional transmission planning requirements should apply to a merchant developer only after it is operating under a Commission-approved OATT. Dayton Power and Light contends that while any transmission facility that is necessary to meet NERC reliability criteria, regardless of ownership, should be required to be included in the transmission planning process, merchant and independent projects planned for nonreliability reasons can be developed independently of the transmission planning process, subject to appropriate interconnection requirements.

76. Other commenters emphasize the importance of allowing merchant and independent developers to participate actively in the transmission planning process.⁸³

Committee on Electricity, New York PSC, Organization of MISO States, Pacific Gas and Electric, Ohio Commission, SPP, San Diego Gas & Electric, South Carolina Electric & Gas, Transmission Access Policy Study Group, Transmission Agency of Northern California, Transmission Dependent Utility Systems, and Xcel.

⁸³ *E.g.*, Green Energy Express, ITC Holdings, Pattern Transmission, and Starwood.

Generally, these commenters argue that merchant and independent transmission developers should either participate in the transmission planning process as early as practical, at the beginning of the transmission planning cycle, or as soon as they have a proposal that is developed well enough to be considered. Pattern Transmission also suggests that the Commission should better define the transmission planning process and the roles of its participants to ensure a level playing field for independent transmission developers.

77. The questions about whether an incumbent transmission owner's right of first refusal unreasonably impedes merchant or independent transmission development and, if so, how this impediment could be addressed, also generated extensive comments. Many commenters state that a right of first refusal does not unreasonably impede merchant and independent transmission development.⁸⁴ Various commenters present a range of reasons that it is appropriate for an incumbent transmission provider to have a right of first refusal, including that the incumbent transmission owner: (1) has a legally enforceable obligation to maintain reliability on its systems and faces penalties for

⁸⁴ *E.g.*, Allegheny Companies, AEP, Ameren, Baltimore Gas and Electric, Dominion, EEI, Great River Energy, Integrys, et al., Sun Flower and Mid-Kansas, Large Public Power Council, MidAmerican, Midwest ISO Transmission Owners, National Grid, Northern Tier Transmission Group, Old Dominion, PPL, PSEG Companies, Ohio Commission, San Diego Gas & Electric, Southern California Edison, Southern Companies, WestConnect Planning Parties, and Xcel. However, Old Dominion suggests that the Commission could eliminate the right of first refusal if merchant and independent transmission developers were subject to the same rules and had the same responsibilities as incumbent transmission owners, and could recover their costs through the RTO/ISO tariff.

noncompliance; (2) is obligated under state law to provide reliable service at the lowest reasonable cost; (3) may be required to build facilities included in an RTO's or ISO's regional plan, an obligation that merchant and independent transmission developers lack; (4) is best situated to develop transmission facilities within its service territory, as it is most familiar with the design and operation of its system, its customers' needs, and state and local permitting and siting processes; and (5) may be able to provide transmission services at a lower cost than a merchant or independent transmission developer because it enjoys economies of scale with respect to the staff and resources necessary to maintain and operate new transmission facilities.

78. Some commenters contend that the right of first refusal should be preserved because an incumbent transmission owner that voluntarily joined an RTO or ISO did so with the understanding that it would retain the right to invest in and earn a return on new facilities within its system.⁸⁵ According to Midwest ISO Transmission Owners, eliminating a right of first refusal could provide a disincentive for RTO membership. Similarly, the California ISO asserts that without a right of first refusal, a transmission owner may have less incentive to participate in an RTO or ISO.

79. However, other commenters argue that a right of first refusal impedes transmission development and provides an undue advantage to an incumbent transmission owner.⁸⁶

⁸⁵ *E.g.*, Ameren, MidAmerican, and Midwest ISO Transmission Owners.

⁸⁶ *E.g.*, American Forest and Paper, AWEA, Californians for Renewable Energy, EPSA, Indicated Partners, Modesto Irrigation District, National Wind, NextEra, Renewable Energy Systems Americas, Startrans, Starwood, Transmission Access Policy
(continued)

Such commenters present a number of reasons for eliminating a right of first refusal, including the following: (1) a right of first refusal provides a disincentive for a merchant or independent developer to propose a project, especially a proposal for a transmission facility that spans multiple utilities' service territories, because any investment that it makes in developing a proposal may be lost if an incumbent transmission owner can exercise its right of first refusal or otherwise delay the project or prevent construction of the project; (2) by discouraging competition and new entry, a right of first refusal likely increases costs to ratepayers; and (3) a merchant or independent transmission developer may have difficulty obtaining financing if investors perceive that its proposed project could be subject to a right of first refusal or is otherwise at a disadvantage compared to a project sponsored by an incumbent transmission owner.

80. Among other comments on this issue, Startrans claims that for an incumbent transmission owner, a Commission-approved right of first refusal effectively creates a federal franchise for transmission development derived from a state franchise for retail electricity. Transmission Agency of Northern California contends that a right of first refusal also may "diminish the incentive for the incumbent utilities to conceive projects in their own service territory."⁸⁷

81. Responding to arguments in favor of a right of first refusal, some commenters argue that concerns about the reliability of a merchant or independent transmission

Study Group, Transmission Agency of Northern California, and Transmission Dependent Utility Systems.

⁸⁷ Transmission Agency of Northern California at 3.

developer's project are unfounded, as the merchant or independent transmission developer will be subject to NERC reliability standards and to the same penalties for noncompliance as an incumbent transmission owner.⁸⁸ Pattern Transmission states that a merchant or independent developer has a financial incentive to construct and operate facilities safely and reliably in accordance with all applicable regulatory and industry standards, as its investment is at risk if it does otherwise. With regard to an incumbent transmission owner's obligation to build, some commenters assert that it is not a burden, but rather a privilege, as the incumbent transmission owner is assured the opportunity to recover its costs and earn a return on its investment through the rate base. These commenters argue that a merchant or independent developer would be willing to compete for such an obligation.⁸⁹ In response to concerns that a merchant or independent developer would submit an inaccurately low bid to construct a proposed transmission facility, some commenters claim that such a developer is no more likely to do so than an incumbent transmission owner.⁹⁰ These same commenters argue that, contrary to what some commenters assert, an incumbent transmission owner will not leave an RTO or ISO if the right of first refusal is eliminated.

82. While some commenters advocate elimination of all rights of first refusal, other commenters support more limited restrictions. For example, Exelon states that "where an independent developer bids on transmission expansion that is justified under existing

⁸⁸ *E.g.*, Green Energy Express and Pattern Transmission.

⁸⁹ *E.g.*, Indicated Partners and Startrans.

⁹⁰ *E.g.*, Indicated Partners.

planning criteria and will be included in rate base, the incumbent transmission owner should be required to match the bid to invoke its right of first refusal.”⁹¹ Several commenters argue that a right of first refusal should be allowed for reliability-based projects, but may not be necessary for economic-based or other projects.⁹² While AWEA and LS Power both maintain that the right of first refusal should be eliminated, they contend that if the right of first refusal is preserved then those practices should apply only to local reliability projects. Moreover, AWEA asserts that a right of first refusal should be required to be exercised within ninety days. Similarly, ITC Holdings contends that a right of first refusal will continue to impede transmission development if the time for exercising it is allowed to continue indefinitely, and Pacific Gas and Electric argues that any right of first refusal should be exercised in a timely manner. Transmission Access Policy Study Group, however, states that the Commission may need to take other steps in addressing this issue in addition to limiting the time in which a right of first refusal may be exercised. In addition, several commenters contend that placing restrictions on a right of first refusal makes the practice no less discriminatory.⁹³

83. EEI argues that while “in general, applicability of a right of first refusal does not create an impediment to transmission planning or development” and that in many cases, “incumbent transmission owners are better situated to build needed transmission within their franchised service territories,” if the Commission finds it necessary to address the

⁹¹ Exelon at 12.

⁹² *E.g.*, Allegheny Companies, Dominion, Large Public Power Council, and SPP.

⁹³ *E.g.*, Indicated Partners.

exercise of a right of first refusal, it should do so on a case-specific basis.⁹⁴ Similarly, the California ISO recommends that the Commission allow the right of first refusal to be addressed through individual RTO and ISO stakeholder processes, rather than adopting generic right of first refusal regulations. Pacific Gas and Electric states that this proceeding should not preempt the California ISO's development of a right of first refusal proposal. In contrast, SPP states that additional clarification and a generally applicable policy regarding the right of first refusal is necessary. The Organization of MISO States argues that, while a right of first refusal may limit competition, any modifications must recognize various state regulatory structures and respect state jurisdiction and statutes. The Alabama PSC argues that the Commission should adopt policies that encourage merchant transmission development only if the state commissions in a region support such policies.

84. In response to the question in the October 2009 Notice regarding barriers to merchant and independent transmission developers' participation in the regional transmission planning process other than a right of first refusal, several commenters state that there are none or that they are unaware of any.⁹⁵ However, Pattern Transmission suggests that the uncertainty of recovering the costs associated with participation in the transmission planning process can be a barrier to participation by merchant and independent transmission developers, particularly if the planning process is inefficient

⁹⁴ EEI at 9-10.

⁹⁵ *E.g.*, Allegheny Companies, Californians for Renewable Energy, Integrys, *et al.*, Maine PUC and Public Advocate, New York PSC, and Xcel.

and deadlines are not met. Pattern Transmission also asserts that an incumbent transmission owner has an advantage in developing proposals as it has priority access to data. Green Energy Express states that the Commission should ensure "a level playing field with regard to the flow of information, the determination of need, and related interactions between an RTO or ISO or other transmission planning region, incumbent transmission owners and developers, and independent, nonincumbent developers."⁹⁶

85. LS Power states that there are several additional barriers to third party developers' participation in regional transmission planning processes, some of which are unique to certain markets. For example, LS Power states that there are regions in which an independent developer cannot become a transmission owner until it has completed a project and owns the resulting transmission facility. Additionally, LS Power states that it is difficult to develop a project in a region where the load-serving entity is also a transmission owner, as the incumbent utility is often responsible for both generation and transmission planning and resource procurement and may have an incentive to expand its rate base by investing in transmission infrastructure rather than support independent transmission development.

86. Northern Tier Transmission Group suggests that some merchant transmission developers self-impose a barrier to successful participation in the transmission planning process in that they do not submit comparable planning data. As such, Northern Tier Transmission Group is unable to include their projects in its analytical studies.

⁹⁶ Green Energy Express at 10.

2. Proposed Reforms Regarding Nonincumbents

87. Based on the comments submitted in response to the October 2009 Notice, there appear to be opportunities for undue discrimination and preferential treatment against nonincumbent transmission developers within existing regional transmission planning processes. Where an incumbent transmission provider has a right of first refusal, a nonincumbent transmission developer risks losing its investment in developing a proposal for submittal to the regional transmission planning process, even if that proposal is selected for inclusion in the regional transmission plan. We are concerned that it may be unduly discriminatory or preferential to deny a nonincumbent transmission developer that sponsors a project that is included in a regional transmission plan the rights of an incumbent transmission provider that are created by a transmission provider's OATT or agreements subject to the Commission jurisdiction.

88. In addition, under these circumstances, nonincumbent transmission developers may be less likely to participate in the regional transmission planning process. If the regional transmission planning process does not consider and evaluate projects proposed by nonincumbents, it cannot meet the principle of being "open." Moreover, such a planning process may not result in a cost-effective solution to regional transmission needs and projects that are included in a transmission plan therefore may be developed at a higher cost than necessary. The result may be that regional transmission services may be provided at rates, terms and conditions that are not just and reasonable.

89. To address these issues, we propose a framework that reflects the following reforms, including the elimination from a transmission provider's OATT or agreements

subject to the Commission's jurisdiction of provisions that establish a federal right of first refusal for an incumbent transmission provider with respect to facilities that are included in a regional transmission plan. Neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission-approved OATT or agreement, receive different treatment in a regional transmission planning process. Further, both should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a facility that it sponsors in a regional transmission planning process and that is selected for inclusion in the regional transmission plan. The Commission proposes that the tariff changes to implement these proposed reforms would be developed through an open and transparent process involving the public utility transmission provider, its customers, and other stakeholders.

90. First, we propose to require that each public utility transmission provider must revise its OATT to demonstrate that the regional transmission planning process in which it participates has established appropriate qualification criteria for determining an entity's eligibility to propose a project in the regional transmission planning process, whether that entity is an incumbent transmission owner or a nonincumbent transmission developer. These criteria must be included in the public utility transmission provider's OATT and must not be unduly discriminatory or preferential. However, it would not be unduly discriminatory or preferential to have appropriate qualification criteria for all potential transmission owners. Such criteria should be designed to demonstrate that each potential transmission owner has the necessary financial and technical expertise to develop,

construct, own, operate, and maintain transmission facilities.⁹⁷ Any such criteria must be approved by the Commission. Although we do not propose here to establish a single set of qualification criteria that would apply in all regional transmission planning processes, we seek comment on whether we should do so and if so, what these criteria should be. Instead, we propose that each public utility transmission provider, in cooperation with customers and other stakeholders in its transmission planning region, must participate in a regional transmission planning process that develops qualification criteria that satisfy the requirements of this Proposed Rule.

91. Second, we propose to require that each public utility transmission provider must revise its OATT to include a form by which a prospective project sponsor would provide information in sufficient detail to allow the proposed project to be evaluated in the regional transmission planning process.⁹⁸ In connection with the other aspects of the framework discussed in this section, we also propose to require that all proposals to be considered in a given transmission planning cycle must be submitted by a single, specified date, to minimize the opportunity for other entities to propose slight modifications to already submitted projects.

⁹⁷ Nothing would preclude the incumbent transmission owner from agreeing to operate and maintain the facilities. Additionally, nothing in this Proposed Rule is intended to change existing RTO and ISO operational procedures and practices.

⁹⁸ The information about its proposed project that a sponsor provides also should include, as relevant, engineering studies, cost analyses, and any other detailed reports completed by the project sponsor as needed to facilitate evaluation of the project in the regional transmission planning process.

92. Third, we propose to require that each public utility transmission provider participate in a regional transmission planning process that evaluates the proposals submitted to the regional planning process through a transparent and not unduly discriminatory or preferential process. Each public utility transmission provider would be required to describe in its OATT the process used for evaluating whether to include a proposed transmission facility in the regional transmission plan.⁹⁹

93. Fourth, with respect to facilities that are included in a regional transmission plan, we propose to require removal from a transmission provider's OATT or agreements subject to the Commission's jurisdiction provisions that establish a federal right of first refusal for an incumbent transmission provider.¹⁰⁰ We also propose to require each public utility transmission provider to amend its OATT to describe how the regional transmission planning process in which it participates provides for the sponsor (whether an incumbent transmission provider or a nonincumbent transmission developer) of a facility that is selected through the regional transmission planning process for inclusion in

⁹⁹ The description would need to provide sufficient detail so that an entity that proposed a project could determine why the project was included or not included in the regional transmission plan. In addition to addressing concerns about undue discrimination or preference, the description would facilitate understanding of the relative weight placed on various benefits associated with competing proposals (e.g., one proposal might address only a reliability-driven transmission need, while another proposal might also provide greater benefits in terms of congestion relief or advancement of public policy requirement established by state or federal laws or regulations that a transmission planning region has identified).

¹⁰⁰ If a Commission-approved tariff or agreement contains a reference to a right provided under state or local laws or regulations, such a provision would not be subject to this requirement.

the regional transmission plan to have a right, consistent with state or local laws or regulations, to construct and own that facility.

94. Moreover, because a regional transmission planning process may result in modifications to proposed projects in order to better meet the needs of the region, the public utility transmission provider must ensure that its regional transmission planning process has a mechanism to determine which proposal the modified project is most similar to, with the sponsor of the most similar project having the right, consistent with state or local laws or regulations to construct and own the facilities.

95. Fifth, we propose to require that if a proposed project is not included in a regional transmission plan and if the project's sponsor resubmits that proposed project in a future transmission planning cycle, that sponsor would have the right to develop that project under the foregoing rules even if one or more substantially similar projects are proposed by others in the future transmission planning cycle. The OATT must state that this priority to develop the proposed facility continues for a defined period of time (e.g., for resubmission annually in subsequent transmission planning cycles over a 5-year period).

96. Sixth, we propose to require that, if an incumbent transmission project developer may recover the cost of a transmission facility for a selected project through a regional cost allocation method, a nonincumbent transmission project developer must enjoy that same eligibility. More specifically, each public utility transmission provider must participate in a regional planning process that provides that, when a project proposed by a nonincumbent transmission developer is included in a regional transmission plan, that developer must have an opportunity comparable to that of an incumbent transmission

owner to recover the costs associated with developing the project and constructing the transmission facility. Costs associated with a project that is not included in the regional transmission plan, whether proposed by an incumbent or by a nonincumbent transmission provider, may not be recovered through a transmission planning region's cost allocation process.

97. We emphasize that these proposed reforms would apply only to facilities that are evaluated in a regional transmission planning process and selected for inclusion in a regional transmission plan. We do not propose to modify any existing obligation for an incumbent transmission owner to build unsponsored projects that are identified as necessary in a regional transmission plan.¹⁰¹ In addition, where an incumbent transmission owner has the right to build, own, and recover costs for upgrades to its own existing transmission facilities (e.g., tower change out and reconductoring), such right would not be affected by the reforms proposed here.

98. We also emphasize that these proposed reforms would affect only a right of first refusal established in a transmission provider's OATT or agreements subject to the

¹⁰¹ For example, in some RTO and ISO regions, transmission owners have obligations to build certain transmission facilities identified by the RTO or ISO. As new transmission owners, including nonincumbent transmission owners, join the RTO or ISO, they will incur the obligations accompanying that status in the RTO or ISO's tariff and other governing documents. We note that provisions imposing such obligations may need to be modified to reflect how they will apply to nonincumbent transmission project developers. We also note that before turning to a transmission owner with such an obligation, the RTO or ISO could conduct a competitive bidding process to assign construction rights for an unsponsored project in its regional transmission plan.

Commission's jurisdiction. This Proposed Rule does not address, propose to change, or seek to preempt any state or local laws or regulations.

99. Finally, we do not propose here to require a transmission developer that does not seek to use the regional cost allocation process to participate in the regional transmission planning process, as some commenters recommend. For example, because a merchant transmission developer assumes all financial risk for developing its project and constructing the proposed facilities, it is unnecessary to require such a developer to participate in a regional transmission planning process for purposes of identifying the beneficiaries of its project or securing eligibility to use a regional cost allocation method. A developer that does not seek to use the regional cost allocation process nevertheless would be required to comply with all reliability requirements applicable to facilities in the transmission planning region in which its project would be located. In addition, such a developer is not prohibited from participating—and, indeed, is encouraged to participate—in the regional transmission planning process.

100. As discussed above, in response to the October 2009 Notice, many commenters link the right of first refusal for an incumbent utility to its obligation to construct new facilities if called upon to do so. While the Commission acknowledges these comments, we preliminarily find that these two practices are not, and should not be, linked within regional transmission planning processes. That is, while a public utility transmission owner may have accepted an obligation to build in relation to its membership in an RTO or ISO, this obligation is not directly dependent on that transmission provider having a corresponding right of first refusal with regard to a proposal to construct and own a new

transmission facility located in that region. What is important from the Commission's perspective is that the documents approved by the Commission must not be unduly discriminatory. The Commission preliminarily finds that neither incumbent nor nonincumbent transmission facility developers should, as a result of a Commission approved OATT or agreement, receive different treatment in the transmission planning and selection process, and both should share similar benefits and obligations commensurate with that participation.

101. We seek comment on how the reforms proposed in this section of the Proposed Rule would affect the rights, obligations, and responsibilities of incumbent and nonincumbent transmission providers. In particular, we seek comment on the relationship or lack of relationship between a right of first refusal and an obligation to build. We also seek comment on whether it would be appropriate to retain a federal right of first refusal in an OATT or other documents subject to the Commission's jurisdiction. If not, why not? If so, would it be appropriate to retain an obligation to build for an incumbent transmission provider while removing a federal right of first refusal for that incumbent?

D. Interregional Coordination

1. The Need for Interregional Planning Reforms

102. As discussed above, the transmission planning principles established in Order Nos. 890 and 890-A establish a framework for transmission planning at the local and regional levels. In Order No. 890-A, the Commission emphasized that effective regional planning should include coordination among regions. Further, the Commission stated that regions

and subregions should coordinate as necessary to share data, information and assumptions to maintain reliability and allow customers to consider the resource options that span the regions.¹⁰² In several of the Order No. 890 compliance orders, the Commission requested more detailed information regarding compliance with this aspect of the regional participation principle.¹⁰³

103. Within that Order No. 890 and 890-A framework, transmission providers in certain parts of the country have organized subregional transmission planning groups for the purpose of collectively developing plans for upgrades on their combined transmission systems. These subregional transmission plans are then analyzed at a regional level to ensure that, if implemented, they will be simultaneously feasible and meet reliability requirements.¹⁰⁴ Additionally, some neighboring transmission providers have undertaken joint transmission planning pursuant to bilateral agreements.¹⁰⁵ However, as observed in

¹⁰² Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 226.

¹⁰³ See, e.g., *Southern Co. Servs., Inc.*; 124 FERC ¶ 61,265, at P 70 (2008); *United States Department of Energy – Bonneville Power Administration*, 124 FERC ¶ 61,054, at P 65 (2008); *Southwest Power Pool, Inc.*, 124 FERC ¶ 61,028, at P 49 (2008).

¹⁰⁴ Such analysis is consistent with one aspect of the Regional Participation transmission planning principle that the Commission established in Order No. 890. On that issue, the Commission stated: “[I]n 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 of integrate new resources ...” Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 523.

¹⁰⁵ See, e.g., *Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.* (Midwest Independent Transmission System Operator, Inc., Second Revised Rate Schedule FERC No. 5; PJM Interconnection, L.L.C. Second Revised Rate Schedule FERC No. 38).

the October 2009 Notice, there are few processes in place to analyze whether alternative interregional solutions would more efficiently or effectively meet the needs identified in individual regional transmission plans.¹⁰⁶

104. The October 2009 Notice posed several questions related to this issue, including whether existing transmission planning processes are adequate to identify and evaluate potential solutions to needs affecting the systems of multiple transmission providers. The October 2009 Notice also sought comment as to what processes should govern the identification and selection of projects that affect multiple systems.¹⁰⁷

105. In response to the October 2009 Notice, some commenters state that the need for supplemental interregional transmission planning processes cannot be evaluated until stakeholders gain more experience with the regional transmission planning processes conducted pursuant to Order No. 890, and thus oppose Commission action on this issue at this time.¹⁰⁸ Other commenters state that the lack of interregional planning is a considerable problem and that transmission planning could be enhanced by increasing the amount of coordination that occurs between neighboring transmission planning regions.¹⁰⁹

¹⁰⁶ October 2009 Notice at 2.

¹⁰⁷ *Id.* at 3.

¹⁰⁸ *E.g.*, American Transmission, Consolidated Edison, et al., Dominion, Eastern Interconnection Planning Collaborative Analysis Team, Imperial Irrigation District, New York ISO, Public Power Council, South Carolina Electric & Gas, and Southern Companies.

¹⁰⁹ *E.g.*, Duke, Exelon, NextEra, Ohio Commission, Old Dominion, Organization of MISO States, PSEG Companies, Transmission Access Policy Study Group, and
(continued)

106. More specifically, several commenters advocate expansion of interregional transmission planning, but disagree as to the extent to which interregional coordination should be institutionalized. Proposals range from requiring regional transmission planning entities to comply with Order No. 890 transmission planning principles,¹¹⁰ to requiring greater coordination among existing transmission planning regions,¹¹¹ to expanding the authorities of regional transmission planning entities.¹¹² Some commenters suggest that the Commission should require interregional transmission planning or develop *pro forma* seams agreements that describe the requirements for coordinating transmission planning with a neighboring transmission planning region.¹¹³

107. San Diego Gas & Electric, for example, states that, in the West, transmission planning is a hodgepodge of balkanized processes resulting in a flood of proposed interstate transmission facilities but with virtually no consideration given to which of the proposed facilities would be most effective in meeting the needs of the broadest set of constituents. San Diego Gas & Electric also states that little serious consideration is

Transmission Dependent Utility Systems.

¹¹⁰ *E.g.*, Old Dominion.

¹¹¹ *E.g.*, AWEA, Pioneer Transmission, PSEG Companies, Public Interest Organizations & Renewable Energy Groups, Transmission Access Policy Study Group, and Transmission Dependent Utility Systems.

¹¹² Regional transmission planning entities would be empowered “to make specific project recommendations at the end of the planning process and to enter binding, near-judicial findings of fact and conclusions related to the need and economic benefits of specific projects or solutions.” San Diego Gas & Electric at 6.

¹¹³ *E.g.*, AEP, Energy Future Coalition, Old Dominion, Pioneer Transmission, Public Interest Organizations & Renewable Energy Groups, SPP, Transmission Access Policy Study Group, and Transmission Dependent Utility Systems.

given to how various project proposals could be modified, combined, or eliminated so as to make the best possible use of available transmission corridors, minimize adverse environmental impacts, and enhance overarching system efficiencies.¹¹⁴

108. Pioneer Transmission states that it has a unique perspective on interregional transmission planning issues, as it spent the last year and a half working with the Midwest ISO and PJM in an effort to develop extra high voltage transmission facilities that will be located in both the Midwest ISO and PJM footprints. Pioneer Transmission states that although the Midwest ISO and PJM have undertaken various studies and have worked cooperatively with Pioneer Transmission, they have been hampered in their efforts to assess the Pioneer project for inclusion in their transmission plans because neither RTO has in place formal procedures for evaluating interregional projects.¹¹⁵

109. The Ohio Commission states in its comments that "[j]ust as the development of RTOs and ISOs was encouraged to better coordinate individual transmission owners' and operators' plans, the development of inter-regional planning committees to review and coordinate individual and RTO and ISO plans should be encouraged."¹¹⁶ The California ISO states that it would be easier to analyze and justify transmission facilities that would be located in more than one region if the underlying data were consistent in all of the areas that are part of evaluating the transmission project in question.¹¹⁷ Similarly, Public

¹¹⁴ San Diego Gas & Electric at 5.

¹¹⁵ Pioneer Transmission at 1-2.

¹¹⁶ Ohio Commission Comments at 6.

¹¹⁷ California ISO at 8.

Interest Organizations & Renewable Energy Groups state that the Commission should require coordinated transmission infrastructure plan development by regional or interregional transmission planning authorities informed by interconnection-wide assessments and broad stakeholder input.

110. The October 2009 Notice also recognized that proposals to implement interconnectionwide transmission planning were being developed in response to the above-noted funding opportunities that DOE offered under the American Recovery and Reinvestment Act of 2009. The October 2009 Notice observed that it was not clear whether those activities would result in a regular process for jointly identifying and evaluating alternatives to solutions identified in transmission plans developed through existing transmission planning processes conducted in accordance with Order No. 890.¹¹⁸

111. In response to the October 2009 Notice, some commenters state that interconnectionwide transmission planning undertaken pursuant to the ARRA should be given a chance to mature before the Commission takes additional action with respect to transmission planning.¹¹⁹ Other commenters emphasize that funding under the ARRA is an important one-time opportunity, but should not be viewed as a prerequisite for initiating or expanding upon other transmission planning efforts.¹²⁰ For example, Exelon states that the ARRA-funded transmission planning for the Eastern Interconnection is a

¹¹⁸ October 2009 Notice at 2-3.

¹¹⁹ *E.g.*, ColumbiaGrid, NARUC, New England States' Committee on Electricity, and Organization of MISO States.

¹²⁰ *E.g.*, Eastern Interconnection Planning Collaborative Analysis Team, Entergy, and Progress Energy.

positive effort, but is aimed at evaluating what would happen under various scenarios rather than at evaluating solutions and identifying the best solution for any given transmission planning problem. AWEA states that the Commission should not rely on interconnectionwide transmission planning undertaken pursuant to the ARRA as the sole means for reforming the transmission planning process because the ARRA-funded efforts cannot be expected to lead to the near-term changes that need to be implemented in order to support development of renewable energy resources.

112. The Commission supports and encourages the interconnectionwide transmission planning efforts being undertaken pursuant to the ARRA. As noted above, broad participation in sessions to date related to these efforts suggests that the availability of federal funds to pursue interconnectionwide transmission planning has increased awareness of the potential for greater coordination among regions in transmission planning. The Commission anticipates that the ARRA-funded efforts will enhance transmission planning by, among other actions, building upon local and regional transmission planning processes and improving capabilities to model the development of transmission enhancements for the various scenarios of interest to state and federal policy makers and other stakeholders, as well as Canadian provincial policy makers in the Western Interconnection. We emphasize that this Proposed Rule, which does not require interconnectionwide planning or cost allocation, is not intended to interfere with the efforts already underway in ARRA-funded transmission planning initiatives.

113. However, even with these important steps toward interconnection-wide scenario analysis, the Commission remains concerned that the lack of coordinated transmission

planning processes across the seams of neighboring transmission planning regions could be needlessly increasing costs for customers of transmission providers. These circumstances may result in transmission rates that are unjust and unreasonable. Therefore, the Commission proposes reforms that are intended to improve coordination between neighboring transmission planning regions with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that could address transmission needs more efficiently than separate intraregional facilities.

2. Proposed Interregional Planning Reforms

114. We propose to require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its neighboring transmission planning regions within its interconnection to address transmission planning issues, as discussed below.¹²¹ This coordination between transmission planning regions must be reflected in an interregional transmission planning agreement to be filed with the Commission.

115. The interregional transmission planning agreement may be developed on behalf of the public utility transmission providers within multiple transmission planning regions. For example, two RTOs may set forth the requirements of their interregional transmission planning coordination as part of an overall joint operating agreement between them. A public utility transmission provider that is not in an RTO or ISO may, for example, work

¹²¹ This proposal does not require a public utility transmission provider to enter into an interregional transmission planning agreement with a neighboring transmission planning region in another interconnection.

with other transmission providers that participate in its regional transmission planning process to create and enter into a multilateral interregional transmission planning agreement with transmission providers in a neighboring transmission planning region. Although not required under this proposal, we encourage public utility transmission providers to explore possible multilateral interregional transmission planning agreements among several, or even all, regions within an interconnection, building on processes developed through the ARRA-funded transmission planning initiatives. We note that multilateral interregional transmission planning agreements may minimize the growing number of planning meetings that some stakeholders suggest pose barriers to their meaningful participation in the planning processes, given their limited resources.

116. The interregional transmission planning agreement must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions with respect to facilities that are proposed to be located in both regions, as well as interregional facilities that are not proposed but that could address transmission needs more efficiently than separate intraregional facilities.

117. While the Commission encourages every interregional transmission planning agreement to be tailored to best fit the needs of the regions entering into the agreement, there are certain elements that we propose each public utility transmission provider must ensure are included in any interregional transmission planning agreement in which it participates. Including these elements will help to ensure a proactive, comprehensive process. Specifically, we propose that an interregional transmission planning agreement

must include: (1) a commitment to coordinate and share the results of respective regional transmission plans to identify possible interregional facilities that could address transmission needs more efficiently than separate intraregional facilities; (2) an agreement to exchange at least annually planning data and information; (3) a formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both regions; and (4) a commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

118. With respect to the third proposed requirement for an interregional transmission planning agreement, the Commission proposes that the sponsor of a project that would be located in both transmission planning regions to which that agreement applies must first propose its project in the transmission planning process of each of those transmission planning regions. The Commission further proposes that such a submission would trigger a procedure established by the interregional transmission planning agreement, under which the transmission planning regions would coordinate their reviews of and jointly evaluate the proposed project. The Commission proposes that such coordination and joint evaluation must be conducted in the same general timeframe as, rather than subsequent to, each transmission planning region's individual consideration of the proposed project. Finally, the Commission proposes that inclusion of the interregional transmission project in each of the relevant regional transmission plans would be a prerequisite to application of an interregional cost allocation method that satisfies the cost allocation principles proposed below in this NOPR.

119. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule, including the proposed required elements of an interregional transmission planning agreement and any other elements that should be part of an interregional transmission planning agreement. In particular, we seek comment on how such an agreement would be implemented in non-RTO or ISO regions and on the impact that an interregional transmission planning agreement would likely have on the development of interregional transmission facilities.

120. We recognize that development of interregional transmission planning agreements would take time and would necessarily depend on progress at the regional level.

Accordingly, the Commission proposes to require the interregional transmission planning agreements to be submitted to the Commission no later than one year after the effective date of the final rule issued in this proceeding.

V. Proposed Reforms: Cost Allocation

A. Introduction

1. Order No. 890's Transmission Planning Principle on Cost Allocation for New Transmission Facilities

121. In Order No. 890, the Commission found that there is a close relationship between transmission planning, which identifies needed transmission facilities, and the allocation of costs of the transmission facilities in the plan. The Commission stated that knowing how the costs of new transmission facilities would be allocated is critical to the development of new infrastructure, because transmission providers and customers cannot

be expected to support the construction of new transmission unless they understand who will pay the associated costs.¹²²

122. In light of this close relationship, the Commission included a principle entitled “Cost Allocation for New Projects” among the Order No. 890 transmission planning principles. The Commission stated that the Order No. 890 Cost Allocation principle was intended to apply to projects that did not fit under existing cost allocation methods. As examples of such projects, the Commission cited regional projects involving several transmission owners and economic projects that are identified pursuant to the Order No. 890 economic planning studies principle for transmission planning, rather than through individual requests for transmission service.¹²³

123. The Commission did not impose a particular cost allocation method in Order No. 890, but instead permitted public utility transmission providers, customers, and other stakeholders to determine a method that would be appropriate given the needs of the region. While allowing this flexibility among regions, the Commission also stated that providing some overall guidance on the issue was appropriate. The Commission stated that when considering a dispute over cost allocation, it would exercise its judgment by weighing several factors. First, the Commission stated that it would consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause the costs to be incurred and those that otherwise benefit from them. Second, the

¹²² Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 557.

¹²³ *Id.* P 558.

Commission stated that it would consider whether a cost allocation proposal provides adequate incentives to construct new transmission. Third, the Commission stated that it would consider whether the proposal is generally supported by state authorities and participants across the region.¹²⁴

124. The Commission also stated that these factors are particularly important as applied to economic projects that are identified pursuant to the Order No. 890 economic planning studies principle for transmission planning, such as upgrades to reduce congestion or enable groups of customers to access new generation. The Commission stated that, as a general matter, the beneficiaries of any such project should agree to support its costs. The Commission recognized, however, that there are free rider problems associated with new transmission investment, such that customers who do not agree to support a particular project may nonetheless receive substantial benefit from it. The Commission also stated that a range of solutions to free rider problems is available, noting that different regions have attempted to address those problems in a variety of ways.¹²⁵

125. To comply with the cost allocation principle, the Commission directed each public utility transmission provider to clearly define the details of its cost allocation method as part of a new attachment to its OATT. The Commission stated that each proposal should identify the types of new projects that are not covered under previously existing cost

¹²⁴ *Id.* P 559.

¹²⁵ *Id.* P 561 (“[D]ifferent regions have attempted to address such issues in a variety of ways, such as by assigning transmission rights only to those who financially support a project or spreading a portion of the cost of certain high-voltage projects more broadly than the immediate beneficiary/supporters of the project.”).

allocation methods and, therefore, would be affected by the Order No. 890 cost allocation principle.¹²⁶ The Commission also stated that it is important that each region address these cost allocation issues up front, at least in principle, rather than having them relitigated each time a project is proposed.¹²⁷ The Commission explained that up-front identification of how the cost of a facility will be allocated will allow transmission providers, customers, and potential investors to make the decision whether or not to build that facility on an informed basis.¹²⁸

126. After several rounds of compliance filings, the Commission approved various public utility transmission providers' proposals pursuant to the cost allocation principle. The Commission found that the proposals adequately identified both the types of new projects that were not covered under previously existing cost allocation methods and new methods for allocating the cost of those projects.

127. Particularly in transmission planning regions outside of the RTO and ISO footprints, many of the cost allocation methods that the Commission accepted in the Order No. 890 compliance proceedings rely exclusively on a "participant funding" approach to cost allocation. Under a participant funding approach to cost allocation, the

¹²⁶ *Id.* P 558.

¹²⁷ *Id.* P 561.

¹²⁸ Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 251. The Commission also stated that neither adoption of a cost allocation method nor identification of an upgrade (whether driven by reliability or economics) in a transmission plan triggers an obligation to build. *Id.*

costs of a new transmission facility are allocated only to entities that volunteer to bear those costs.

128. For example, El Paso Electric proposed in its Order No. 890 compliance filing to use a cost allocation method in which such entities would share the costs proportionally based on each participant's desired use of the facility to be constructed.¹²⁹ Other members of WestConnect, such as Public Service Company of Colorado, filed and now use similar participant funding cost allocation methods.¹³⁰ South Carolina Electric & Gas included in its Order No. 890 compliance filing the Southeast Inter-Regional Participation Process (SIRPP) provisions stating that costs for economics-driven upgrades will be born entirely by the transmission owner that builds the facilities.¹³¹ Similarly, Entergy filed and had approved a method where the costs for projects developed under its Regional Planning Process and its interregional transmission planning process would be born by the party that constructs the facilities.¹³² ColumbiaGrid and the Northern Tier Transmission Group both utilize a study committee process whereby alternative cost allocation methods can be proposed for projects within their respective regions.¹³³ However, both ColumbiaGrid and Northern Tier

¹²⁹ *El Paso Electric Company*, 124 FERC ¶ 61,051, at P 44 (2008).

¹³⁰ *Xcel Energy Services, Inc. - Public Service Company of Colorado*, 124 FERC ¶ 61,052 (2008).

¹³¹ *South Carolina Electric & Gas Company*, 127 FERC ¶ 61,275, at P 50 (2009).

¹³² *Entergy Services, Inc.*, 127 FERC ¶ 61,272 (2009).

¹³³ *See Avista Corporation*, 128 FERC ¶ 61,065 (2009) and *Idaho Power Company*, 128 FERC ¶ 61,064 (2009).

Transmission Group use a process where, if no agreement on cost allocation among the study team participants or the project proponents is obtained, the entities requesting the project will bear the costs.

2. October 2009 Notice and Subsequent Comments

129. As discussed above, in the October 2009 Notice, the Commission posed a number of questions with respect to allocating the cost of transmission facilities. Those questions drew wide-ranging responses as to whether further Commission action on cost allocation is needed at this time and, if so, what that action should be.

130. Among the commenters, there is general agreement that the Commission should not supersede existing, ongoing processes in various parts of the country that are attempting to address regional and interregional cost allocation issues.

131. Nonetheless, commenters supporting further Commission action on cost allocation at this time generally assert that the Commission should provide more detailed guidelines or principles for allocating the costs of new transmission facilities.¹³⁴ Many commenters argue that a clear path to cost recovery is necessary for a new transmission project to move beyond the evaluation stage and to be included in any regional transmission planning process and ultimately to proceed to construction.¹³⁵ Such commenters indicate that risks associated with cost recovery—together with the risks associated with

¹³⁴ *E.g.*, APPA, National Rural Electric Coops, Transmission Access Policy Study Group, Transmission Dependent Utility Systems, and California ISO.

¹³⁵ *E.g.*, American Transmission, AWEA, E.ON Climate & Renewables North America, Energy Future Coalition, and NextEra.

permitting and siting—are among the most significant obstacles to the construction of a new transmission facility, especially if customers that are allocated costs do not perceive that they will benefit from the proposed facility.¹³⁶ Old Dominion emphasizes that many of the obstacles inhibiting transmission development are interrelated, but that greater certainty on cost allocation would likely ease access to capital for proposed facilities.¹³⁷

132. Several commenters specifically address cost allocation as an impediment to the development of generation to satisfy renewable portfolio standards implemented by the states.¹³⁸ AWEA, for example, states that cost allocation policies are the biggest impediment to construction of new transmission facilities, regardless of location, and that costs should be assigned to all entities that benefit from a new facility. AWEA further comments that a participant funding cost allocation method does not achieve that goal.¹³⁹ These commenters also state that uncertainty over cost allocation imposes significant costs on customers attempting to export energy from renewable resources and inhibit planning for the integration of the most economic generation resources into the transmission grid. Maine PUC and Public Advocate state that the existing ISO-NE cost

¹³⁶ *E.g.*, AWEA, Transmission Dependent Utility Systems, Xcel, Transmission Access Policy Study Group, and National Rural Electric Coops.

¹³⁷ Old Dominion at 26.

¹³⁸ *E.g.*, AWEA at 9-10, American Transmission and Exelon.

¹³⁹ AWEA at 4. *See also* Transmission Access Policy Study Group at 25-27.

allocation methods are not optimal when considering large amounts of wind integration.¹⁴⁰

133. Similarly, the majority of commenters that address cost allocation for large, interregional transmission facilities agree that the Commission should provide more guidance on cost allocation.¹⁴¹ Some commenters complain that as a general matter, the Commission has addressed cost allocation methods only for facilities within the footprint of a single transmission provider or a single RTO or ISO, and not for interregional projects. For example, AEP states that it has experienced delays in developing transmission facilities that cross RTO boundaries as a result of uncertainty over cost allocation, as well as difficulties with how the facilities are to be planned.

134. Some of these commenters assert that the expansion of regional power markets and the increasing adoption by state governments of renewable energy requirements have led to a growing need for new transmission facilities that cross several utility and/or RTO or ISO regions. These commenters generally support, or state that they do not oppose, the Commission establishing a process to help stakeholders address cost allocation matters over larger geographic areas. For example, California ISO and the California Commission comment that, although cost allocation within the California ISO works well, they support the Commission creating a process to consider cost allocation over a larger region in the West.

¹⁴⁰ Maine PUC and Public Advocate at 7-8.

¹⁴¹ *E.g.*, AEP, ITC Holdings, and Exelon.

135. In addition, the comments in response to the October 2009 Notice reflect a general consensus that those who share in the benefits of transmission projects should also share in their costs. However, there is no consensus on what types of benefits should be considered or how such benefits should be calculated. Certain commenters, for example, support recognition of a broad spectrum of benefits that may stem from transmission development, such as environmental impacts, land conservation and energy security.¹⁴² Other commenters urge the Commission to avoid a uniform approach to determining the benefits of transmission projects.¹⁴³

136. Several commenters suggest that if the Commission decides to establish a default cost allocation method for new transmission facilities, such a method should be employed and enforced only when stakeholders are unable to agree upon their own regional cost allocation method or methods.¹⁴⁴ For example, American Transmission, National Grid, Northern Tier Transmission Group, and NEPOOL Participants state that the Commission could create a generic cost allocation method as a backstop, which would apply when parties or regions could not come to their own agreement. Other commenters express the

¹⁴² *E.g.*, AEP, AWEA, Baltimore Gas and Electric, Energy Future Coalition, Green Energy Express, ITC Holdings, MidAmerican, National Audubon Society, NextEra, and Public Interest Organizations & Renewable Energy Groups.

¹⁴³ *E.g.*, ColumbiaGrid, ConEd, Delaware Municipal and Southwestern Electric, and Northeast Utilities.

¹⁴⁴ *E.g.*, American Transmission, National Grid, Northern Tier Transmission Group, and NEPOOL Participants.

view that the Commission should create one or more rebuttable presumptions about who benefits from various types of facilities in order to make cost allocation easier.¹⁴⁵

137. Finally, many commenters state that no further generic Commission action on cost allocation is needed at this time because the processes in their own regions already address, or are now working to address, cost allocation. For example, in the Southeast, some commenters state that their processes for cost allocation are working well and argue that the Commission should continue to allow regional flexibility on cost allocation processes.¹⁴⁶ Similarly, in the West, some commenters state that cost allocation in their region is not a problem.¹⁴⁷

B. Legal Authority and Need for Reform

138. Based on the comments received in response to the October 2009 Notice, the Commission believes that further reform with respect to transmission cost allocation methods may be necessary in order to ensure that the rates, terms and conditions of transmission service in interstate commerce are just and reasonable and not unduly discriminatory or preferential.

1. The Cost Causation Principle

139. Under sections 205 and 206 of the FPA, the Commission is responsible for ensuring that the rates, terms, and conditions for transmission of electricity in interstate

¹⁴⁵ *E.g.*, ITC Holdings, MidAmerican, PJM, Solar Energy Industries, and WIRES.

¹⁴⁶ *E.g.*, Entergy, Southern Companies, and Florida Transmission Providers.

¹⁴⁷ *E.g.*, ColumbiaGrid, Northern Tier Transmission Group, Transmission Agency of Northern California, Salt River Project and WestConnect Planning Parties.

commerce are just, reasonable, and not unduly discriminatory or preferential.¹⁴⁸ With respect to this responsibility, the Commission and the courts have found that the costs of jurisdictional transmission facilities must be allocated in a manner that satisfies the “cost causation” principle.

140. The U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has defined the cost causation principle as follows: “[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.”¹⁴⁹ The U.S. Court of Appeals for the Seventh Circuit (Seventh Circuit) recently quoted and elaborated on that definition, stating, “All approved rates must reflect to some degree the costs actually caused by the customer who must pay them. Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. To the extent that a utility benefits from the costs of new facilities, it may be said to have ‘caused’ a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed.”¹⁵⁰

¹⁴⁸ 16 U.S.C. 824d, 824e.

¹⁴⁹ *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (*K N Energy*).

¹⁵⁰ *Illinois Commerce Comm’n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (*Illinois Commerce Commission*) (citing *K N Energy*, 968 F.2d at 1300; *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 708 (D.C. Cir. 2000); *Pacific Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004); *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (*Midwest ISO Transmission Owners*); *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); *Sithe/Independence Power Partners, L.P. v. FERC*, 285 F.3d 1, 4-5 (D.C. Cir. 2002) (*Sithe*); 16 U.S.C. 824d).

The Commission has frequently made similar statements with respect to the cost causation principle. For example, as noted above, the Commission stated in Order No. 890 that one factor it weighs when considering a dispute over cost allocation is whether a cost allocation proposal fairly assigns costs among participants, including those who cause the costs to be incurred and those that otherwise benefit from them.¹⁵¹

141. In applying the cost causation principle, the Commission has generally allocated costs to beneficiaries that have entered a voluntary arrangement with the public utility that is seeking to recover those costs. One example of a voluntary cost recovery arrangement with a public utility is voluntary membership in an RTO or ISO that makes an entity subject to the cost allocation provisions of the RTO's or ISO's tariff.¹⁵² The Commission also has permitted joint-ownership agreements where the owners share the costs of the new transmission facilities.

142. The cost causation principle, however, is not limited to voluntary arrangements. Indeed, if the Commission were limited to allocating costs only to beneficiaries that voluntarily accept those costs, then the Commission could not fulfill its responsibilities under the FPA. If the Commission could not address free rider problems associated with new transmission investment, then it could not ensure that transmission rates are just and reasonable and not unduly discriminatory. The cost causation principle provides that costs should be allocated to those who cause them to be incurred and those that otherwise

¹⁵¹ Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 559.

¹⁵² The Commission notes that RTO or ISO membership does not eliminate the need to satisfy the other aspects of the cost causation principle that are discussed above.

benefit from them, as the Commission also recognized in Order No. 890. In other words, the Commission may determine that an entity's status as a beneficiary of a transmission facility identified through an appropriate process is relevant for purposes of applying the cost causation principle, even if that beneficiary has not entered a voluntary arrangement with (e.g., as a customer of) the public utility that is seeking to recover the costs of that facility.

143. The Commission has expressed a willingness to make such a determination. For example, when presented with concerns about parallel path flow,¹⁵³ the Commission has offered repeatedly that if a public utility can demonstrate that a transaction is a burden on its system, then that utility can propose a transmission service rate for Commission consideration that would account for the unauthorized use of its system.¹⁵⁴ The Commission has cautioned against the hasty submittal of such unilateral filings, describing its general policy as expecting owners and controllers of transmission facilities

¹⁵³ The Commission has described the phenomenon of parallel path flow as follows: "In general, utilities transact with one another based on a contract path concept. For pricing purposes, parties assume that power flows are confined to a specified sequence of interconnected utilities that are located on a designated contract path. However, in reality power flows are rarely confined to a designated contract path. Rather, power flows over multiple parallel paths that may be owned by several utilities that are not on the contract path. The actual power flow is controlled by the laws of physics which cause power being transmitted from one utility to another to travel along multiple parallel paths and divide itself along the lines of least resistance. This parallel path flow is sometimes called 'loop flow.'" *Indiana Michigan Power Co. and Ohio Power Co.*, 64 FERC ¶ 61,184, at 62,545 (1993).

¹⁵⁴ See, e.g., *Amer. Elec. Power Svc. Corp.*, 49 FERC ¶ 61,377, at 62,381 (1989).

to attempt to resolve parallel path flow issues on a consensual, regional basis.¹⁵⁵

Nonetheless, if approved by the Commission, such a proposal to address parallel path flow would allow a public utility to recover costs from a beneficiary of its system in the absence of a voluntary arrangement between the utility and that beneficiary.

144. The Commission also affirmatively required costs of transmission facilities to be allocated to beneficiaries in the absence of a voluntary arrangement in a series of orders involving the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) and PJM Interconnection, L.L.C. (PJM). Specifically, the Commission directed Midwest ISO and PJM to develop cost allocation methods for new facilities in one of their footprints that benefit entities in the other's footprint.¹⁵⁶ Echoing precedent applying the cost causation principle, the Commission later conditionally accepted a proposal that Midwest ISO and PJM submitted in compliance with that directive on the grounds that it "more accurately identifies the beneficiaries and allocates the associated costs" than did the cost allocation methods that were previously in place.¹⁵⁷

¹⁵⁵ *Id.* See also *Southern California Edison Co.*, 70 FERC ¶ 61,087, at 61,241-42 (1995).

¹⁵⁶ *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168, at P 60 (2004) (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,251, at P 56-57 (2004)). The Commission noted that Midwest ISO and PJM had committed in a Joint Operating Agreement to develop such a method for allocating the costs of certain facilities through their joint regional planning committee. *Id.* The Commission did not base the above-noted directive on the existence of the Joint Operating Agreement, which Midwest ISO and PJM developed in order to comply with a previous Commission directive. See *Alliance Cos.*, 100 FERC ¶ 61,137, at P 48, 53 (2002).

¹⁵⁷ *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,194, at P 10 (2005). See also *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,084

(continued)

145. These examples show that the Commission has asserted its authority to allocate the costs of jurisdictional facilities to beneficiaries whether or not those beneficiaries have entered into a voluntary agreement with the public utility that is seeking to recover those costs.

146. In addition, courts have affirmed that the cost causation principle allows the Commission to allocate at least some types of costs to beneficiaries that are not customers of the public utility that is seeking to recover the costs in question. For example, the D.C. Circuit addressed this issue in a case that involved a proposal for Midwest ISO to recover administrative costs through a charge that would apply to transmission loads subject to the Midwest ISO's tariff rates: i.e., new wholesale loads and unbundled retail loads, but not bundled retail loads and loads served pursuant to grandfathered contracts.¹⁵⁸

Describing the core issue as whether the Commission's orders comported with the cost causation principle, the D.C. Circuit found that the Commission reasonably allocated the administrative costs more broadly than Midwest ISO proposed.¹⁵⁹ After stating that the subject costs were the administrative costs of having an ISO, the D.C. Circuit found that

(2008); *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,102 (2009).

¹⁵⁸ *Midwest ISO Transmission Owners*, 373 F.3d 1361. The D.C. Circuit stated that the subject costs "are primarily MISO's startup expenses – particularly those pertaining to the MISO Security Center – and certain expenses pertaining to the creation and administration of MISO's open access tariff." *Id.* at 1369.

¹⁵⁹ *Id.* at 1370.

the Commission correctly determined that bundled and grandfathered loads should share the cost of having an ISO because they drew benefits from Midwest ISO.¹⁶⁰

147. Thus, in applying the cost causation principle, the Commission may allocate costs of a transmission facility to a beneficiary identified through an appropriate process, such as a Commission-approved transmission planning process, even if that beneficiary has not entered a voluntary arrangement with the public utility that is seeking to recover the costs of that facility. After satisfying this standard with respect to beneficiary identification, the cost causation principle also requires the Commission to ensure that the costs allocated to a beneficiary under a cost allocation method are at least roughly commensurate with the benefits that are expected to accrue to that entity.¹⁶¹ On this point, the D.C. Circuit has explained that “the cost causation principle does not require exacting precision in a ratemaking agency’s allocation decisions.”¹⁶²

2. Need for Reform

148. The Commission’s responsibility under FPA sections 205 and 206 to ensure that transmission rates are just and reasonable and not unduly discriminatory or preferential is not new, nor is the Commission’s recognition of the cost causation principle. However,

¹⁶⁰ *Id.* at 1370-71.

¹⁶¹ *Illinois Commerce Commission*, 576 F.3d at 476-77 (“We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.”). *See also Midwest ISO Transmission Owners*, 373 F.3d 1361 at 1369 (“we have never required a ratemaking agency to allocate costs with exacting precision.”); *Sithe*, 285 F.3d 1 at 5.

¹⁶² *Midwest ISO Transmission Owners*, 373 F.3d 1361 at 1371 (citing *Sithe*, 285 F.3d 1 at 5).

the circumstances in which the Commission must fulfill its statutory responsibilities change with developments in the electric industry, such as changes with respect to the demands placed on the transmission grid.

149. The Commission has previously recognized changes in circumstances that warranted changes in the manner by which public utilities recover transmission costs. In the early 1990s, the Commission identified “dramatic changes which the electric industry has faced, and will face in the near term,” such as “increased reliance on market forces to meet power supply needs; new market entrants such as exempt wholesale generators; a significant number of utility mergers and combinations; more highly integrated operation of various power pools; and substantial bulk power trading among electric systems,” as well as the initial filing of open access transmission tariffs.¹⁶³ To account for those developments and the industry’s changing needs, the Commission issued a policy statement that increased flexibility with respect to transmission pricing.¹⁶⁴

150. Many of those changes have not only continued but also accelerated in recent years. For example, as commenters stated in response to the October 2009 Notice, the further expansion of regional power markets has led to a growing need for new transmission facilities that cross several utility, RTO, ISO or other regions. The

¹⁶³ See *Notice of Technical Conference and Request for Comments in Inquiry Concerning the Commission’s Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act*, 58 FR 36400, at 36401 (1993).

¹⁶⁴ *Policy Statement in Inquiry Concerning the Commission’s Pricing Policy for Transmission Services Provided by Public Utilities under the Federal Power Act*, FERC Stats. & Regs., Regulations Preambles January 1991 – June 1996 ¶ 31,005 (1994).

industry's continuing transition from relatively localized trading to larger regional power markets also results, among other effects, in broader diffusion of the benefits associated with transmission upgrades and new transmission facilities.

151. Similarly, the increasing adoption of state resource policies, such as renewable portfolio standard measures, has contributed to rapid growth of location-constrained renewable energy resources that are frequently remote from load centers, as well as a growing need for new transmission facilities that cross several utility and/or RTO or ISO regions. Transmission facilities that are needed to comply with state renewable portfolio standard measures illustrate the increasing potential for benefits associated with meeting public policy-driven transmission needs.

152. More generally, as stated above, challenges associated with allocating the cost of transmission appear to have become more acute as the need for transmission infrastructure has grown. As noted above, constructing new transmission facilities requires a significant amount of capital. Therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. However, there are few rate structures in place today that provide both for analysis of the beneficiaries of a transmission facility that is proposed to be located within a transmission planning region that is outside of an RTO or ISO, or in more than one transmission planning region, and for corresponding allocation and recovery of the facility's costs. The lack of such rate structures creates significant risk for transmission developers that they will have no identified group of customers from which to recover the cost of their investment. In addition, cost allocation within RTO or

ISO regions, particularly those that encompass several states, is often contentious and prone to litigation because it is difficult to reach an allocation of costs that is perceived as fair. Some comments filed in response to the October 2009 Notice present these types of concerns and state the resultant uncertainty regarding cost allocation remains an impediment to development of needed transmission facilities.

153. The risk of the free rider problems associated with new transmission investment that the Commission described in Order No. 890 is also particularly high for projects that affect multiple utilities' transmission systems and therefore may have multiple beneficiaries. With respect to such projects, any individual beneficiary has an incentive to defer investment in the hopes that other beneficiaries will value the project enough to fund its development. On one hand, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, increases this incentive and, in turn, the likelihood that needed transmission facilities will not be constructed in a timely manner. On the other hand, if costs are allocated to entities that will receive no benefit from a transmission facility, then those entities are more likely to oppose inclusion of the facility in a regional transmission plan or to otherwise impose obstacles that delay or prevent the facility's construction.

154. In light of these challenges and recent developments affecting the industry, the Commission is concerned that existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities and, thus, may result in rates that are not just and reasonable or are unduly discriminatory or preferential.

C. Proposed Reforms

155. The Commission proposes to amend its regulations to address the concerns discussed above.

156. First, we propose to more closely align transmission planning and cost allocation processes. A transmission planning process includes a facility in a transmission plan in order to achieve a specific purpose or purposes, such as to avoid an impending violation of a Reliability Standard, reduce congestion and thereby increase access to lower-cost resources, or enable compliance with public policy requirements established by state or federal laws or regulations. Because such purposes involve the identification of expected beneficiaries—either explicitly or implicitly—establishing a closer link between transmission planning and cost allocation will address in part the Commission’s concern that existing cost allocation methods may not appropriately account for benefits associated with new transmission facilities.

157. The Commission has previously suggested that transmission planning at least on a regional basis is closely related to cost allocation. As noted above, this premise underlies the Commission’s establishment in Order No. 890 of a transmission planning principle on cost allocation for new transmission facilities. In addition, the Commission has explained that it may be appropriate to have different cost allocation methods for facilities that are planned for different purposes or pursuant to different transmission planning processes. For example, the Commission distinguished between existing facilities in Midwest ISO and PJM for which it found that license plate rates are appropriate, and new facilities in

those regions for which it approved broader cost allocation methods.¹⁶⁵ The Commission found it significant that Midwest ISO and PJM plan the construction of new facilities based on each RTO's independent transmission planning process, which helps to ensure that new projects are necessary to meet the reliability and economic needs of each RTO's system as a whole. The Commission also noted that Midwest ISO and PJM plan certain new facilities pursuant to a joint RTO planning process under a Joint Operating Agreement. By contrast, the Commission stated that decisions to build existing facilities within Midwest ISO and PJM were not made as part of any regional planning process.¹⁶⁶

158. The Commission recognizes that identifying which types of benefits are relevant for cost allocation purposes, which entities are receiving those benefits, and the relative benefits that accrue to various beneficiaries can be difficult and controversial. The Commission believes that a transparent transmission planning process is the appropriate forum to address these issues. In addition, addressing these issues through the transmission planning process would increase the likelihood that facilities included in transmission plans are actually constructed, rather than being included in a transmission plan only to later encounter cost allocation disputes that prevent their construction.

159. Accordingly, the Commission proposes to require that every public utility transmission provider have in place a method, or set of methods, for allocating the costs of new transmission facilities that are included in the transmission plan produced by the

¹⁶⁵ *Amer. Elec. Power Serv. Corp. v. Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,083, at P 13-24 (2008).

¹⁶⁶ *Id.* P 96.

transmission planning process in which it participates. If the public utility transmission provider is an RTO or ISO, then the method or methods would be required to be set forth in the RTO or ISO tariff. In other transmission planning regions, each public utility transmission provider located within the region would be required to set forth in its tariff the method or methods for cost allocation used in its transmission planning region.

160. An RTO or ISO or the public utility transmission providers in a transmission planning region may have a single cost allocation method for all new transmission facilities or different methods for different types of facilities. For example, cost allocation methods may distinguish among facilities that are driven by needs associated with maintaining reliability, relieving congestion, and achieving public policy requirements established by state or federal laws or regulations, all of which would be required to be considered in the regional transmission planning process as explained elsewhere in this Proposed Rule. The Commission recognizes that several transmission planning regions that have different cost allocation methods by type of project currently have transmission planning procedures and cost allocation methods that refer only to the first two categories of transmission projects. The Proposed Rule would permit a public utility transmission provider or transmission planning region to distinguish or not distinguish among these three types of transmission facilities, as long as each of the three is considered in the transmission planning process and there is a means for allocating the costs of each type of facility to beneficiaries.

161. Second, we propose to require that each public utility transmission provider within a transmission planning region develop a method for allocating the costs of a new

interregional transmission facility between the two neighboring transmission planning regions in which the facility is located or among the beneficiaries in the two neighboring transmission planning regions.

162. Third, to ensure that the cost allocation method or methods are just and reasonable and not unduly discriminatory or preferential, we propose to assess each cost allocation method based upon the cost allocation principles set out in the following sections, one set of principles for intraregional facilities and another for interregional facilities. To reiterate, we propose that the cost allocation method or methods be applied to new transmission facilities included in the transmission plan produced by the transmission planning process in which the public utility transmission provider participates.

163. Finally, we note that under our proposals, public utility transmission providers will have the first opportunity to develop cost allocation methods for intraregional and interregional transmission facilities in consultation with customers and other stakeholders. In the event that no agreement can be reached, the Commission would use the record in the relevant compliance filing proceeding as a basis to develop a cost allocation method or methods that meets the Commission's proposed requirements.

1. Intraregional Cost Allocation

164. An intraregional transmission facility is defined as a transmission facility located entirely within the geographic boundaries of one transmission planning region. As proposed here, each RTO or ISO on behalf of its transmission owning members, or the individual public utility transmission providers in a non-RTO or ISO transmission planning region, would be required to demonstrate through a compliance filing that it has

a cost allocation method or methods that address cost recovery for each new transmission facility included in its regional transmission plan and that satisfy the following principles:

- (1) The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.¹⁶⁷ In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.¹⁶⁸
- (2) Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.
- (3) If a benefit to cost threshold is used to determine which facilities have sufficient net benefits to be included in a regional transmission plan for the

¹⁶⁷ *Illinois Commerce Commission*, 576 F.3d at 476-77 (“We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars.”). *See also Midwest ISO Transmission Owners*, 373 F.3d 1361 at 1369 (“we have never required a ratemaking agency to allocate costs with exacting precision.”); *Sithe*, 285 F.3d 1 at 5.

¹⁶⁸ As discussed above, the Commission proposes to require each public utility transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.

purpose of cost allocation, it must not be so high that facilities with significant positive net benefits are excluded from cost allocation. A transmission planning region or public utility transmission provider may want to choose such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a greater ratio.

- (4) The allocation method for the cost of an intraregional facility must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs.¹⁶⁹ However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades that may be required in another region and, if there is an agreement for the original region to bear costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the entities in the original region.

¹⁶⁹ In addition, the Commission preliminarily finds that this principle does not affect the cross-border cost allocation methods developed by PJM and the Midwest ISO in response to Commission directives related to their intertwined configuration. *Midwest Indep. Transmission Sys. Operator, Inc.*, 113 FERC ¶ 61,194, at P 10 (2005); *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,084 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,102 (2009).

- (5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.
- (6) A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.

165. In proposing these principles, the Commission does not intend to prescribe a uniform approach to cost allocation for new intraregional transmission facilities. To the contrary, we recognize that regional differences may warrant distinctions in cost allocation methods among transmission planning regions. Therefore, this Proposed Rule would allow the public utility transmission providers in each transmission planning region to develop a transmission cost allocation method that best suits the needs of that transmission planning region.

166. However, the Commission proposes that, if the public utility transmission providers in a transmission planning region, in consultation with customers and other stakeholders, cannot agree on a cost allocation method for new intraregional transmission facilities that satisfies these principles, the Commission would use the record in the relevant compliance filing proceeding as a basis for applying these principles to develop

a cost allocation method that meets the Commission's requirements. Consistent with the Commission's intention not to prescribe a uniform approach, this cost allocation method would not necessarily be the same for every transmission planning region where the public utility transmission providers are unable to agree on a cost allocation method that satisfies the principles.

167. The Commission recognizes that several approaches to cost allocation may satisfy the proposed principles. For example, a postage stamp cost allocation method may be appropriate where all customers within a specified transmission planning region are found to benefit from the use or availability of a facility or class or group of facilities (e.g., all transmission facilities at 345 kV or higher), especially if the distribution of benefits associated with a class or group of facilities is likely to vary considerably over the long depreciation life of the facilities amid changing power flows, fuel prices, population patterns, and local economic developments. Similarly, other methods that propose cost allocation to a narrower class of beneficiaries may be appropriate, provided that the method reflects an evaluation of beneficiaries and is adequately defined and supported by the transmission planning region.

168. In addition, the principles proposed in this rulemaking do not foreclose the opportunity for a transmission developer or individual customer to voluntarily assume the costs of a new transmission facility. In other words, the proposed principles would not prohibit voluntary participant funding. However, if a transmission developer believes that others in the transmission planning region may benefit from a new transmission facility and want to seek broader cost allocation, then that developer must be permitted to

propose its project in the regional transmission planning process that will evaluate the project's beneficiaries. If the facility is included in the regional transmission plan, the costs of that facility must be eligible for allocation pursuant to the Commission-approved method for allocating the cost of a new transmission facility in that plan.¹⁷⁰ As stated above, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, exacerbates the free rider problem that the Commission described in Order No. 890. Such a cost allocation method would not satisfy the proposed principles.

169. With regard to a new transmission facility that is located entirely within one transmission owner's service territory, a transmission owner may not unilaterally invoke the regional cost allocation method to require the allocation of the costs of a new transmission facility to other entities in its transmission planning region. However, if the regional transmission planning process determines that a new facility located solely within a transmission owner's service territory would provide benefits to others in the region, allocating the facility's costs according to that region's intraregional cost allocation method would be permitted.

2. Interregional Cost Allocation

170. An interregional transmission facility is one that is located within two or more transmission planning regions. In the past, most transmission upgrades were planned and

¹⁷⁰ However, certain transmission developers may seek to participate in the regional transmission planning process only for coordination purposes (e.g., to perform a reliability check for a participant-funded or merchant transmission project), in which case the transmission plan would not include a cost allocation for such projects.

constructed to meet the needs of customers within a given transmission planning region. However, new transmission facilities located within multiple transmission planning regions are now being considered by transmission providers in various parts of the nation. For example, as discussed above, development of renewable energy resources is increasing rapidly, in part in response to state renewable portfolio standard requirements. However, many of these resources are located far from load centers. New transmission facilities located within multiple transmission planning regions may be necessary to deliver the output of these renewable energy resources.

171. There are few rate structures in place today that provide for the allocation and recovery of costs of interregional transmission facilities. We are concerned that the absence of clear cost allocation rules for interregional transmission facilities could impede the development of such facilities, because of uncertainty regarding recovery of associated costs. In addition, the combined size of the multiple transmission planning regions in which an interregional facility would be located may increase the potential for both free ridership and the allocation of costs to those that receive no benefit from a facility.

172. Therefore, we propose to require that the public utility transmission providers located in each pair of neighboring transmission planning regions develop a mutually agreeable method for allocating between the two transmission planning regions the costs of a new transmission facility that is located within both regions and that is eligible for interregional cost recovery pursuant to the region's interregional transmission planning agreement developed in accordance with the requirement proposed above. In an RTO or

ISO region, we propose that the method must be filed to become a part of the relevant tariffs. In other transmission planning regions, we propose that the cost allocation method be filed as part of the OATT of each public utility transmission provider in the region.

173. A group of three or more transmission planning regions within an interconnection—or all of the transmission planning regions within an interconnection—may agree on and file a common method for allocating the costs of a new interregional transmission facility. However, the Commission does not propose to require such agreements among more than two neighboring transmission planning regions.

174. Each cost allocation method filed in accordance with this proposal would be required to comply with the following principles:

- (1) The costs of a new interregional facility must be allocated to each transmission planning region in which that facility is located in a manner that is at least roughly commensurate with the estimated benefits of that facility in each of the transmission planning regions. In determining the beneficiaries of interregional transmission facilities, transmission planning regions may consider benefits including, but not limited to, those associated with maintaining reliability and sharing reserves, production cost savings and congestion relief, and meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs.¹⁷¹

¹⁷¹ As discussed above, the Commission proposes to require each public utility
(continued)

- (2) A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that facility.¹⁷²
- (3) If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a facility with significant positive net benefits from cost allocation. The public utility transmission providers located in the neighboring transmission planning regions may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold, may not include a ratio of benefits to costs that exceeds 1.25 unless the pair of regions justifies and the Commission approves a higher ratio.
- (4) Costs allocated for an interregional facility must be assigned only to transmission planning regions in which the facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that facility is not located. However, the interregional planning process

transmission provider to amend its OATT such that its local and regional transmission planning processes explicitly provide for consideration of public policy requirements established by state or federal laws or regulations that may drive transmission needs.

¹⁷² For example, a DC line that runs from a first transmission planning region, through a second transmission planning region, and into a third transmission planning region, with no tap in the second region, may not provide any benefits to the second region.

must identify consequences for other transmission planning regions, such as upgrades that may be required in a third transmission planning region and, if there is an agreement among the transmission providers in the regions in which the facility is located to bear costs associated with such upgrades, then the interregional cost allocation method must include provisions for allocating the costs of the upgrades within the transmission planning regions in which the facility is located.

- (5) The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.
- (6) The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve public policy requirements established by state or federal laws or regulations. Each cost allocation method must be set out and explained in detail in the compliance filing for this rule.

175. As with intraregional cost allocation, we are not proposing to require a uniform method of cost allocation for interregional transmission facilities. There may be legitimate reasons for the public utility transmission providers located in neighboring transmission planning regions to adopt different cost allocation methods. The

Commission recognizes that several approaches to cost allocation may satisfy the proposed principles.¹⁷³

176. Therefore, we propose to allow methods for allocating the costs of new interregional facilities to differ among pairs of transmission planning regions, as long as each method satisfies the proposed interregional cost allocation principles listed above. Moreover, the method used for allocating interregional transmission facility costs between any two transmission planning regions may be different from the method used by the public utility transmission providers located in either of those transmission planning regions to allocate the costs of new intraregional facilities. In addition, the cost allocation method used by the public utility transmission providers located in a transmission planning region to allocate the costs of new intraregional facilities could be different from the cost allocation method by which the public utility transmission providers in the same transmission planning region further allocate costs to be borne by that transmission planning region pursuant to an agreed-upon method for allocating the costs of interregional facilities.

177. Similar to our proposal for intraregional transmission facilities, we propose that if the public utility transmission providers in coordination with their customers and other stakeholders in a pair of neighboring transmission planning regions cannot agree on a

¹⁷³ For the reasons discussed above with respect to cost allocation for intraregional transmission facilities, a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, would not satisfy the proposed principles for interregional cost allocation.

cost allocation method for new interregional transmission facilities that satisfies these principles, then the Commission would use the record in the relevant compliance filing proceedings as a basis for applying the principles to develop an interregional cost allocation method that meets the Commission's requirements. Such a cost allocation method would not necessarily be the same for every pair of neighboring transmission planning regions that is unable to agree on a cost allocation method that satisfies the principles.

178. We seek comment on any issue of interest or concern related to the requirements proposed in this section of the Proposed Rule. In particular, we seek comment on the appropriateness and application of the proposed cost allocation principles with respect to new intraregional and interregional transmission facilities. If commenters believe that additional principles should apply to cost allocation for either intraregional or interregional transmission facilities, the Commission asks commenters to submit and explain the need for those principles.

VI. Compliance Filings

179. The Commission proposes that each public utility transmission provider must comply with the requirements of this Proposed Rule. With the exception of the proposed requirements with respect to interregional transmission planning agreements and an interregional cost allocation method or methods, the Commission proposes to require each public utility transmission provider to submit a compliance filing within six months of the effective date of the final rule in this proceeding revising its OATT or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it

meets the proposed requirements set forth in this Proposed Rule.¹⁷⁴ The Commission proposes to require each public utility transmission provider to submit a compliance filing within one year of the effective date of the final rule in this proceeding to demonstrate that it meets the proposed requirements set forth in the Proposed Rule with respect to interregional transmission planning agreements. The Commission proposes to require each public utility transmission provider to submit a compliance filing within one year of the effective date of the final rule in this proceeding revising its OATT as necessary to demonstrate that it meets the proposed requirements set forth in this Proposed Rule with respect to an interregional cost allocation method or methods.

180. The Commission would assess whether each compliance filing satisfies the proposed requirements and principles stated above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of this Proposed Rule.

181. The Commission proposes that transmission providers that are not public utilities would have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.¹⁷⁵

¹⁷⁴ See Appendix B for the proposed *pro forma* Attachment K consistent with this NOPR.

¹⁷⁵ Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760-63.

VII. Information Collection Statement

182. The following collection of information contained in this Proposed Rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.¹⁷⁶ OMB's regulations require approval of certain information collection requirements imposed by agency rules.¹⁷⁷ The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

Burden Estimate: The estimated public reporting burdens for the proposed reporting requirements are as follows.

<u>FERC-917 Proposed Reporting Requirements in RM10-23</u>	<u>Annual Number of Respondents (thousands)</u>	<u>Annual Number of Responses</u>	<u>Hours per Response</u>	<u>Total Annual Hours in Year 1</u>	<u>Total Annual Hours in Subsequent Years</u>
participation in a transparent and open intraregional transmission planning process that meets transmission planning principles, includes consideration of public policy requirements, identifies and evaluates facilities to meet needs, develops cost allocation method, and produces an intraregional transmission plan that	134	134	100 hrs in Year 1; 50 hrs. in subsequent years	13400	6700

¹⁷⁶ 44 U.S.C. 3507(d).

¹⁷⁷ 5 CFR 1320.11.

describes and incorporates a cost allocation method that meets the Commission's principles.					
coordination, development, and filing with the Commission of interregional planning agreements that meet the Commission's requirements, that include consideration of public policy requirements, and that incorporate cost allocation methods that meets the Commission's principles; provide or post ongoing communications, and provide annual data exchange.	134	134	125 hrs. in Year 1; 50 hrs. in subsequent years	16750	6700
conforming tariff changes for local transmission planning, including those related to consideration of public policy requirements; and conforming tariff changes for intraregional and interregional planning.	134	134	50 hrs. in Year 1; 25 hours in subsequent years	6700	3350
Total Estimated Additional Burden Hours, Proposed for FERC-917 in NOPR in RM10-23				36850	16750

Cost to Comply: The Commission has projected costs of compliance for the reporting requirements as follows:

Year 1: \$4,200,900 [36,850 hours X \$114 per hour¹⁷⁸]

Subsequent Years: \$1,909,500 [or 16,750 hours X \$114 per hour]

OMB's regulations require it to approve certain information collection requirements

¹⁷⁸ The estimated cost of \$114 an hour is the average of the hourly costs of: attorney (\$200), consultant (\$150), technical (\$80), and administrative support (\$25).

imposed by an agency rule. The Commission is submitting notification of this Proposed Rule to OMB. The Commission proposes to make the reporting requirements mandatory.

Title: FERC-917

Action: Proposed Collection.

OMB Control No. 1902-0233

Respondents: Electric Utility Transmission Providers. RTOs and ISOs also may file some materials on behalf of their members.

Frequency of responses: Initial filing and subsequent filings.

Necessity of the Information:

183. Building on the reforms in Order No. 890, the Federal Energy Regulatory Commission is proposing amendments to the *pro forma* OATT to correct certain deficiencies in transmission planning and cost allocation requirements for public utility transmission providers. The purpose of this proposed rulemaking is to strengthen the *pro forma* OATT, so that the transmission grid can better support wholesale power markets and ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. We propose to achieve this goal by reforming electric transmission planning requirements and establishing a closer link between cost allocation and regional transmission planning processes.

184. Internal Review: The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and

management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support associated with the information requirements.

185. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director, e-mail: DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873.

For submitting comments concerning the collection of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. Due to security concerns, comments should be sent electronically to the following e-mail address: oir_submission@omb.eop.gov. Please reference OMB Control No. 1902-0233 and the docket number of this proposed rulemaking in your submission.

VIII. Environmental Analysis

186. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.¹⁷⁹ The Commission concludes that neither an Environmental

¹⁷⁹ *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

Assessment nor an Environmental Impact Statement is required for this Proposed Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.¹⁸⁰

IX. Regulatory Flexibility Act Analysis

187. The Regulatory Flexibility Act of 1980 (RFA)¹⁸¹ generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. This Proposed Rule applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888, 889 and 890. The total estimated number of public utility transmission providers that, absent waiver, would have to modify their current OATTs by filing the revised pro forma OATT is 134. Of these public utility transmission providers, an estimated 10 filers, or 7.3% percent, have output of four million MWh or less per year.¹⁸² The Commission does not consider this a substantial

¹⁸⁰ 18 CFR 380.4(a)(15).

¹⁸¹ 5 U.S.C. 601-612.

¹⁸² A firm is "small" if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours. Based on the filers of the annual FERC Form 1 and Form 1-F, as well as the number of companies that have obtained waivers, we estimate that 7.3% of the filers are "small."

number and, in any event, each of these entities retains its rights to waiver of these requirements. The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889 and 890. Accordingly, the Commission certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities.

X. Comment Procedures

188. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 60 days from publication in the FEDERAL REGISTER. Comments must refer to Docket No. RM10-23-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

189. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's web site at <http://www.ferc.gov>. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

190. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE, Washington, DC 20426.

191. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

XI. Document Availability

192. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.gov>) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

193. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

194. User assistance is available for eLibrary and the FERC's web site during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

List of subjects in 18 CFR Part 35

Electric power rates

Electric utilities

Reporting and recordkeeping requirements

By direction of the Commission. Commissioner Moeller is concurring with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 71-7352.

2. Amend § 35.28 as follows:

- a. Paragraph (c)(1) through (c)(1)(iii) are revised.
- b. Paragraph (c)(1)(vi) is revised.
- c. Paragraphs (c)(3), (c)(3)(i), and (c)(3)(ii) are revised.
- d. Paragraphs (c)(4) through (c)(4)(ii) are revised.
- e. Paragraph (d) (1) is revised.
- f. Paragraph (e)(1) is revised.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) Non-discriminatory open access transmission tariffs.

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the open access pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036 (Final Rule on Open Access and Stranded Costs), as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 (Final Rule on Open Access Reforms) and

further revised in Order No. _____, FERC Stats. & Regs. ¶ _____ (Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities), or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,306, Order No. 890, FERC Stats. & Regs. ¶ 32,241, and Order No. _____, FERC Stats. & Regs. ¶ _____.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv) and (c)(1)(v) of this section, the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the open access pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. _____, FERC Stats. & Regs. ¶ _____, and accompanying rates, must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce as of [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], it must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241, as amended by Order No. _____, FERC Stats. & Regs. ¶ _____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. _____, FERC Stats. & Regs. ¶ _____.

(iii) If a public utility owns, controls, or operates transmission facilities used for

the transmission of electric energy in interstate commerce as of [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. _____, FERC Stats. & Regs. ¶ _____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA.

* * * * *

(vi) Any public utility that seeks a deviation from the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. _____, FERC Stats. & Regs. ¶ _____, must demonstrate that the deviation is consistent with the principles of Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. _____, FERC Stats. & Regs. ¶ _____.

* * * * *

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the

pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. _____, FERC Stats. & Regs. ¶ _____, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. _____, FERC Stats. & Regs. ¶ _____.

(i) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed after [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], this requirement is effective on the date that transactions begin under the arrangement or agreement.

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff consistent with Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. _____, FERC Stats. & Regs. ¶ _____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. _____, FERC Stats. & Regs. ¶ _____.

* * * * *

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission a tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. _____, FERC Stats. & Regs. ¶ _____, or such other open access tariff as may be approved by the Commission consistent with Order No. 888, FERC Stats. & Reg. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. _____, FERC Stats. & Regs. ¶ _____.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to the pro forma tariff contained in Order No. 890, FERC Stats. & Regs. ¶ 31,241 as amended by Order No. _____, FERC Stats. & Regs. ¶ _____, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and Order No. _____, FERC Stats. & Regs. ¶ _____.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access tariff is consistent with or superior to the revisions to the pro forma tariff contained in Order No. 888, FERC Stats. & Regs. ¶ 31,036, as revised by the pro forma tariff in Order No. 890, FERC Stats. & Regs. ¶ 31,241 and further revised in Order No. _____, FERC Stats. & Regs. ¶ _____, or any portions thereof, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to

section 206 in accordance with the procedures set forth in Order No., FERC Stats. & Regs. ¶ ____.

(d) Waivers. * * *

(1) No later than [insert date that is 60 days after date of publication of the Final Rule in the FEDERAL REGISTER], or

* * * * *

(e) Non-public utility procedures for tariff reciprocity compliance.

(1) A non-public utility may submit a transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Order No. 888, FERC Stats. & Regs. ¶ 31,036, Order No. 890, FERC Stats. & Regs. ¶ 31,241, and Order No. _____, FERC Stats. & Regs. ¶ ____.

* * * * *

Note: The following appendices will not be published in the Code of Federal Regulations.

**Appendix A: List of Short Names of Commenters on the Federal Energy
Regulatory Commission's Notice of Request for Comments on Transmission
Planning Processes under Order No. 890—Docket No. AD09-8-000, October 2009**

<u>Short Name or Acronym</u>	<u>Commenter</u>
3M	3M Company, High Capacity Conductors
AEP	American Electric Power Service Corporation
Alabama PSC	Alabama Public Service Commission
Allegheny Companies	Allegheny Power and Trans-Allegheny Interstate Line Company
Ameren	Ameren Services Company
American Antitrust Institute	American Antitrust Institute
American Forest and Paper	American Forest & Paper Association
American Transmission	American Transmission Company LLC
APPA	American Public Power Association
AREVA T&D	AREVA T&D Inc.
AWEA	American Wind Energy Association
Baltimore Gas and Electric	Baltimore Gas and Electric Company
Barbara Luchsinger	Barbara Luchsinger
Bay Area Municipal Transmission Group	City of Santa Clara, California; the City of Palo Alto, California; and the City of Alameda, California
Bonneville	Bonneville Power Administration

BP Energy	BP Energy Company
The Brattle Group	Peter Fox-Penner, Johannes Pfeifenberger, and Delphine Hou
California ISO	California Independent System Operator Corporation
CALifornians for Renewable Energy	CALifornians for Renewable Energy, Inc.
California PUC	California Public Utilities Commission
California State Water Project	California Department of Water Resources State Water Project
Calvin Daniels	Calvin Daniels
Chinook and Zephyr	Chinook Power Transmission, LLC and Zephyr Power Transmission, LLC
Clean Line	Clean Line Energy Partners, LLC
Coalition to Advance Renewable Energy Through Bulk Energy Storage	Coalition to Advance Renewable Energy Through Bulk Energy Storage
ColumbiaGrid	ColumbiaGrid
Consolidated Edison, et al.	Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.
Dayton Power and Light	Dayton Power and Light Company
Delaware Municipal and Southwestern Electric	Delaware Municipal Electric Corporation, Inc. and Southwestern Electric Cooperative, Inc.
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation
Eastern Interconnection Planning	Eastern Interconnection Planning

Collaborative Analysis Team	Collaborative Analysis Team
Eastern PJM Governors	Governors of New Jersey, Delaware, Maryland, and Virginia
EEI	Edison Electric Institute
Electricity Consumers Resource Council	Electricity Consumers Resource Council
ENE (Environment Northeast)	ENE Environment Northeast
Energy Future Coalition	Energy Future Coalition
Entergy	Entergy Services, Inc.
E.ON	E.ON U.S. LLC
E.ON Climate & Renewables North America	E.ON Climate & Renewables North America
EPSA	Electric Power Supply Association
Exelon	Exelon Corporation
Federal Trade Commission	Federal Trade Commission
FirstEnergy	FirstEnergy Affiliates
Florida Transmission Providers	Florida Power & Light, Progress Energy Florida, Tampa Electric Company, and JEA
Georgia Transmission Corporation	Georgia Transmission Corporation
Great River Energy	Great River Energy
Green Energy Express	Green Energy Express, LLC
Illinois Commission	Illinois Commerce Commission
Imperial Irrigation District	Imperial Irrigation District (CA)
Independent Power Producers	Independent Power Producers Coalition-

Coalition-West	West
Indicated Partners	Green Energy Express LLC; Transmission Technology Solutions LLC; SouthWestern Power Group II, LLC; Nevada Hydro Company; LS Power Transmission, LLC; and Pattern Transmission LP
Integrays, et al.	Wisconsin Public Service Corporation, Upper Peninsula Power Company, and Integrays Energy Services, Inc.
ISO New England	ISO New England Inc.
ITC Holdings	ITC Holdings Corp.
Kelson Companies	Cottonwood Energy Company LP; Dogwood Energy LLC; and Magnolia Energy LP
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities; Colorado Springs Utilities; CPS Energy (San Antonio); IID Energy, JEA (Jacksonville, FL), Long Island Power Authority; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District, New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities
Long Island Power Authority, et al.	Long Island Power Authority, Consolidated Edison Company of New York, Inc., and Orange and Rockland Utilities, Inc.
Lorraine Fleming	Lorraine Fleming
LS Power	LS Power Transmission, LLC

Given that the U.S. Congress is examining cost allocation at this time, our issuance of this proposed rule comes at a potentially sensitive time. While Congress is now considering several measures that deal directly with issues addressed in this proposed rule, I expect that this Commission will defer to the legislative branch as we move forward in our deliberations. This proposed rule, and the comments to follow, will provide the Congress with the framework of the issues that we consider relevant and the opportunity for Congress to provide further guidance to us. Thus, our action today is not intended to interfere with that process, but rather to add helpful information and evidence that will be useful in the formation of federal legislation.

Also controversial will be the question of whether incumbent utilities should retain rights of first refusal that were created under the Commission's jurisdiction. Alas, the question of whether transmission developers can compete on par with an incumbent transmission-owning utility is no longer theoretical. In recent cases, the Commission has been confronted with particular situations where competitors could be discouraged (or altogether blocked) from building a transmission project if the incumbent utility retains the right of first refusal.² While initial rulings have been rendered in these cases, the generic issue is ready for further discussion in this rulemaking.

Resolving controversial issues is rarely easy and I expect today's proposed rule to be both lauded and criticized. The changes proposed here are significant, but the future success of the organized markets and the nation's electric transmission system depend on resolving these long-debated and controversial issues.

Staff's efforts here have resulted in a proposal that will lead to a much needed conversation on how to best encourage needed capital investment. This will not be an easy matter to address when it comes before the Commission for a vote on the final rule, and for that reason this Commission should carefully consider the comments that we will receive. I will do my part to ensure that this Commission does not lose sight of the ultimate goal: a final rule that results in needed capital investment.

Philip D. Moeller
Commissioner

² *Primary Power, LLC*, 131 FERC ¶ 61,015 (2010) (reh'g pending) and *Cent. Transmission, LLC v. PJM Interconnection L.L.C.*, 131 FERC ¶ 61,243 (2010).

Régie de l'énergie
DOSSIER: 12-3669-2008 Phox 2
DÉPOSÉE EN AUDIENCE
Date: 21 October 2010
Pièces n°: C-2 - \$1 UC

September 16, 2010
Ms. Erica M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Sixth Floor - 900 Howe Street
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

RE: British Columbia Utilities Commission (BCUC)
British Columbia Hydro and Power Authority (BC Hydro)
Open Access Transmission Tariff (OATT) Amendments

I. Application

BC Hydro applies, pursuant to section 59 to 61 of the *Utilities Commission Act (UCA)*,¹ for approval of amendments to the OATT, and related tariff supplements and rate schedules, to reflect the integration of BC Hydro and British Columbia Transmission Corporation (BCTC) pursuant to the *Clean Energy Act, S.B.C. 2010, c. 16 (CEA)*. As part of this submission, BC Hydro also applies to amend certain provisions of the OATT to reflect other housekeeping items.

BC Hydro also seeks an order from the BCUC granting BC Hydro relief from compliance with the terms of Attachment K (Transmission Planning Process) to BC Hydro's OATT until January 1, 2012. Such relief will allow BC Hydro to fully assess its transmission planning process and determine how it will proceed with compliance with the CEA in conjunction with the UCA and the OATT.

II. Background

BC Hydro implemented a Wholesale Transmission Services (WTS) Tariff in 1997 pursuant to BCUC Order Nos. G-31-97 and G-43-98. The WTS Tariff was based on the pro forma open access transmission tariff established by the U.S. Federal Energy Regulatory Commission (FERC) for utilities under its jurisdiction by its landmark Order No. 888 dated April 24, 1996.

¹ R.S.B.C. 1996, Chapter 473.

Pursuant to the *Transmission Corporation Act, S.B.C. 2003* and certain agreements between BC Hydro and BCTC (the *Key Agreements*), responsibility for offering transmission and generator interconnection services shifted to BCTC in 2003, which subsequently obtained BCUC approval of its own OATT effective April 1, 2005.² The *Key Agreements* set forth the respective roles and responsibilities of the parties regarding the operation, management, planning and maintenance of the transmission system owned by BC Hydro. Consistent with the *Key Agreements*, the BCTC OATT distinguished between BCTC as the "Transmission Provider" and BC Hydro as the "Transmission Owner", as defined in the existing OATT. The existing OATT was most recently amended, and approved by the BCUC, on September 10, 2009³ to reflect the pro forma tariff presently established by FERC in Order No. 880 (the *FERC pro forma tariff*).

On June 3, 2010, the CEA received Royal Assent and on July 5, 2010, sections 21 to 33 regarding the integration of BC Hydro and BCTC came into force in accordance with the commencement provisions in section 77 of the CEA. By sections 22 and 23 of the CEA, BCTC's rights, property, assets, included contracts and included permits, and obligations and liabilities transferred by a matter of law to BC Hydro. Thus, BCTC's became BC Hydro's on July 5, 2010 and BC Hydro is now the only entity responsible for operating, managing, planning, and maintaining BC Hydro's transmission system and the OATT. Consequently, BC Hydro is now seeking the BCUC's approval to amend the existing OATT, and related tariff supplements and rate schedules, to reflect the integrated company.

III. Overview of Amendments

BC Hydro remains committed to non-discriminatory open access to transmission, consistent with applicable BCUC decisions and FERC reciprocal access standards. As such, with the transfer of BCTC's OATT to BC Hydro on July 5, 2010, certain amendments are required to the OATT, and related tariff supplements and rate schedules, to reflect this change. In addition, BC Hydro also wishes to concurrently amend the OATT to incorporate changes required as a result of the adoption of Mandatory Reliability Standards in British Columbia and some other minor housekeeping items.

The following is a summary of the proposed amendments which are each discussed in greater detail below:

- changes to reflect BC Hydro as the Transmission Provider;

² Approved by BCUC Order Nos. G-25-05 and G-58-05 dated March 11, 2005 and June 19, 2005, respectively.

³ Approved by BCUC Order No. G-102-09 dated September 10, 2009.

- additional FERC 890 pro-forma tariff language required as a result of the Transmission Provider, now BC Hydro, being a vertically integrated utility;
- amendments to Rate Schedules;
- amendments to Tariff Supplements; and
- other housekeeping items, such as revisions required due to the adoption of the Mandatory Reliability Standards (MRS), changes to the OATT to reflect BC Hydro's credit rating practices and other miscellaneous matters.

To assist in understanding the nature of proposed amendments a Table of Changes is included as Attachment 1. A clean and a black-lined version of the OATT, with Attachments, and its related Rate Schedules is included as Attachments 2 and 3, respectively. Revised Tariff Supplements have been included separately as Attachment 4. Included in Attachment 4 is a summary of changes for Tariff Supplement No. 79, and a black-line version of Tariff Supplement No. 80. Neither a summary of changes nor black-line version has been included for Tariff Supplement No. 78 as only one section (section 7.1) remains from the original Tariff Supplement.

A. Changes to reflect BC Hydro as the Transmission Provider

Although not highlighted in the Table of Changes, a number of changes have been made throughout the OATT including changes to the Terms and Conditions, Attachments, Rate Schedules, and Tariff Supplements that replace the name BCTC with the name BC Hydro. This reflects what is accomplished already by section 24(1) of the CEA, which states:

Subject to subsection (2), a reference to the transmission corporation in any document, including, without limitation, any record, security agreement, lease, included permit, included contract, instrument or certificate that relates to anything transferred to the authority under this Part, is deemed to be a reference to the authority.

Moreover, the integration of BCTC and BC Hydro now results in the OATT now no longer requiring a reference to the Transmission Owner because: 1) it is no longer necessary, due to the Key Agreements having no force and effect as confirmed pursuant to section 33 of the CEA, and 2) this distinction from the Transmission Provider is not part of the FERC pro forma tariff. Thus, a number of clauses contained in the OATT are now no longer relevant, or required, and the majority of the proposed modifications to the OATT reflect this change in circumstances. For example, the stand-alone indemnity Agreement required between BC Hydro, as the Transmission Owner, and an Interconnection Customer in the Standard Generator Interconnection Agreement (SGIA) (refer to Appendix 5 of Attachment M-1) is no longer necessary because BC Hydro is now the signatory to the SGIA and article 18 of the SGIA fully

addresses the issue of indemnity. These types of amendments are noted in the Table of Changes.

B. Additional FERC Pro Forma Tariff Language

This category of amendments includes changes and additions to the existing OATT to incorporate FERC pro forma tariff language that was either revised or excluded by BCTC to more appropriately reflect the relationship established pursuant to the Key Agreements, where BCTC had undertaken the responsibilities of the Transmission Provider and BC Hydro continued as the Transmission Owner.

FERC's pro forma tariff is designed primarily for an integrated utility that owns transmission, distribution and generation systems, such as BC Hydro. The FERC pro forma tariff, therefore, includes some language which assumes that the Transmission Provider is the owner and operator of the transmission system as well as the distribution system and generation facilities. For instance, the FERC pro forma tariff includes language to account for the Transmission Provider's own use of transmission service under the tariff.

Language relating to an integrated utility providing transmission services was originally included in BC Hydro's WTS Tariff, but was subsequently removed under BCTC's OATT as it was not applicable when BCTC was the Transmission Provider. As a result of the integration of BCTC and BC Hydro, BC Hydro now seeks to reinstate such applicable FERC pro forma language because BC Hydro is an integrated utility that owns and operates transmission, distribution and generation assets. These changes are reflected in, for instance, sections 8, 13.3, 14.3, 19.2(c), 20.21.1, 25, and 32.2(c) of the OATT.

In addition, the BCTC OATT varied from the FERC pro forma tariff with respect to the Transmission Provider's redispatch obligations because BCTC did not have available its own generation resources. BC Hydro now seeks to include the FERC pro forma tariff language because BC Hydro, as an integrated utility, does have its own generation resources. These changes are reflected in sections 13.5, 15.4(b), 19.3, and 32.3 of the OATT.

Although BC Hydro is incorporating the FERC pro forma language in relation to redispatch in the above-noted sections, BC Hydro's position with respect to the potential for redispatch opportunities continues to be as submitted in BC Hydro's letter dated February 15, 2007 [sic 2008] to the BCUC in response to Directive 39 of BCUC Order No. G-69-07 and as referenced in BCTC's letter dated December 21, 2007 to the BCUC. As noted in its submission, BC Hydro could not make available any surplus generation which could be used for long-term redispatch. The BCUC accepted the submissions of BC Hydro and BCTC in a letter to BCTC dated February 21, 2008 (refer to Attachment 5 for BCUC letter and accompanying BC Hydro and BCTC submissions).

C. Amendments to Rate Schedules

The current rate schedules reflect the Transmission Provider-Transmission Owner relationship that existed between BCTC and BC Hydro prior to July 5, 2010 with respect to the provision of transmission and ancillary services. Rate Schedules 00 to 10 for transmission and ancillary services reflect the combination of the Transmission Provider's Rate Schedules 100 to 110, the Transmission Owner's Rate Schedules 3000 to 3002, and BC Hydro's Rate Schedules 3011 to 3016 and Tariff Supplement 69 which supported BCTC's ancillary services. With the integration of BCTC and BC Hydro, it is no longer necessary to distinguish between the Transmission Provider's and the Transmission Owner's Rate Schedules and BC Hydro no longer needs to have separate Rate Schedules to provide support to the Transmission Provider for ancillary services that it can now directly provide to transmission customers.

As such, BC Hydro requests the cancellation of:

- Rate Schedules 100 to 110 and Rate Schedules 3000 to 3002; and
- Rate Schedules 3011 to 3016 and Tariff Supplement 69.

In addition, BC Hydro proposes to amend Rate Schedules 00 to 10 to incorporate any necessary provisions that are included in the Rate Schedules to be cancelled – e.g., rate provisions for ancillary services previously provided by BC Hydro, such as Loss Compensation Service, will now need to be included as part of Rate Schedule 09.

Amendments have also been made to the rate schedules to reflect the implementation of the Harmonized Sales Tax.

D. Amendments to OATT-related Tariff Supplements

The OATT-related tariff supplements, which are attached separately as Attachment 4, are the following:

1. Tariff Supplement 1, Canal Plant Agreement (CPA) Support Agreement;
2. Tariff Supplement 2, Generating Plant and Operational Obligations Agreement, as amended (GPOOA); and
3. Tariff Supplement 3, Network Economy Service.

The CPA Support Agreement⁴ (Tariff Supplement 1) is no longer in force and effect as an agreement and is no longer required for the purposes of BC Hydro meeting its transmission-related obligations under the CPA. However, section 7.1 of the CPA Support Agreement addresses the issue of wheeling rates on the BC Hydro system in relation to the Coordination Transfers, as defined in the CPA, and provides clarification on this issue which is not addressed within the terms of the CPA. Section 7.1 of the CPA provides that:

- a) Coordination Transfers to BC Hydro at the Kootenay Interconnection, will be treated like any other BC Hydro resource under BC Hydro's agreements entered into for service under the OATT; and
- b) Coordination Transfers, and ancillary services pursuant to section 6.7 of the CPA, both of which are to be provided by BC Hydro to the Entitlement Parties at the Kootenay Interconnection, will not be included as BC Hydro network load under BC Hydro's agreements entered into for service under the OATT.

The above noted provisions reflect BC Hydro's view that Coordination Transfers – delivered to the Entitlement Parties under the CPA and which are fundamental to the performance of the CPA obligations – provide benefits to the entire transmission network. As a result of this, BC Hydro believes the residual costs should be borne by all network customers in proportion to each customer's network load. This position was submitted and approved pursuant to BCUC Order No. G-41-06. Currently, as was the case in 2006, BC Hydro is the only network customer and pays all of the residual.

For the reasons above, BC Hydro submits that this part of the CPA Support Agreement should continue to exist in an amended and revised Tariff Supplement (BC Hydro Tariff Supplement 78) as provided in Attachment 4. All other provisions of the CPA Support Agreement are no longer necessary, or required, and will not be included in the new Tariff Supplement 78.

The existing Tariff Supplement 2 is the GPOOA between BC Hydro and BCTC.⁵ The GPOOA addresses: (1) the requirements for interconnection for BC Hydro's generating plants with the transmission system as contained in Part B of the GPOOA; and (2) the operating obligations to be supplied by BC Hydro to BCTC for the reliable operation of the electric system as contained in Part C of the GPOOA. Although a detailed formal agreement, such as this, is no longer required between BC Hydro (as the Interconnection Customer) and the Transmission Provider, BC Hydro believes that there are certain provisions in Part B of the GPOOA, with respect to interconnection issues, which should continue to exist in the form of the proposed Tariff Supplement 79.

⁴ Approved by BCUC Order No. G-41-06, dated April 11, 2006.

⁵ The GPOOA was approved by the BCUC letter dated February 27, 2006. Subsequent amendments were approved by BCUC Order No. G-168-08, dated December 23, 2008.

Specifically, BC Hydro proposes that: (1) the existing interconnection requirements for its generating plants continue to be approved by the BCUC, and (2) an equivalent interconnection process for modifications to BC Hydro's generating plants, consistent with the OATT, continue as a separate approved process. Attachment 4 includes a clean version of the new Tariff Supplement No. 79 and a summary of changes which provides guidance on what has been modified, deleted or moved.

The existing Tariff Supplement 3 describes the Network Economy Services obligations. BCTC Tariff Supplement 3 has been renamed BC Hydro Tariff Supplement 80. Tariff Supplement 80 remains largely unchanged with the exception of changes to certain provisions to reflect the fact that BC Hydro is an integrated utility. The proposed changes uphold the spirit and obligations of the Settlement Agreement approved pursuant to BCUC Order No. G-127-06. Attachment 4 includes a clean and black-line version of this Tariff Supplement No. 80.

E. Other Housekeeping Items

In Order No. G-67-09, dated June 8, 2009, the BCUC MRS for British Columbia that include applicable reliability standards for certain generators. Where appropriate, BC Hydro has made changes to the OATT to replace outdated reliability requirements with terms and conditions which are consistent with the MRS framework now applicable in B.C. – e.g., Attachments M-1 (Standard Generator Interconnection Procedures) and Q-1 (Dynamic Scheduling).

In addition, BC Hydro has made minor changes to the insurance provisions in Attachment M-1 (Standard Generator Interconnection Procedures) of the OATT (refer to Appendix 5, section 18.3). The insurance provisions contained in Attachment M-1 are FERC pro forma language and through the review process of this filing it was determined that minor changes were required to more accurately reflect applicable insurance Corporation of British Columbia policies for automobile insurance.

BC Hydro has also made changes to the credit practices applied by BCTC to align with BC Hydro credit procedures (refer to Attachment L) and has made changes to reflect the adoption of the Harmonized Sales Tax.

IV. Relief from Attachment K

BC Hydro is seeking an order from the BCUC granting BC Hydro relief from compliance with the terms of Attachment K (Transmission Planning Process) to BC Hydro's OATT until January 1, 2012.

Attachment K to the OATT was approved by the BCUC in Order No. G-102-09, dated September 10, 2009. Attachment K outlines a process to be followed by BC Hydro when planning projects for the purpose of expanding the capability of the transmission system.

As discussed above, pursuant to the CEA, BC Hydro has taken over the responsibilities of BCTC, including the Attachment K obligations. In addition, the CEA provides that BC Hydro is required to prepare an integrated resource plan that includes, among other things, plans respecting the construction or extension of facilities. As a result of this development and new requirements, BC Hydro is assessing its planning process and determining how it will proceed with compliance with the CEA in conjunction with the UCA and the OATT.

Consequently, BC Hydro is requesting relief from the Attachment K process until January 1, 2012, at which time BC Hydro will have submitted its first integrated resource plan in compliance with section 3(6)(a) of CEA. BC Hydro will also have a better understanding of its planning processes going forward and will seek approval, as required, for any changes to Attachment K that may be necessary.

V. Conclusion

The nature of the majority of the proposed amendments described above primarily reflect the integration of BCTC and BC Hydro. BC Hydro has also taken the opportunity to make some general housekeeping changes to update provisions dealing with insurance and credit requirements, MRS and applicable taxes. BC Hydro's proposed OATT revisions are entirely consistent with the FERC pro forma tariff established by its Order No. 890 and do not introduce substantive changes to the existing OATT Terms and Conditions, Attachments, Rates Schedules and related Tariff Supplements.

The proposed amendments do not impact the service levels or the rights of OATT customers. Therefore, BC Hydro does not believe that customer consultation with respect to the amendments is required.

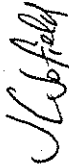
For the reasons stated above, BC Hydro proposes that a public process is not necessary for the BCUC to approve this application. A draft Order is included as Attachment 6 of this application.

The proposed amendments would be effective immediately upon approval by the BCUC and will be applied on a go-forward basis to all new and existing customers.

September 16, 2010
Ms. Elita M. Hamilton
Commission Secretary
British Columbia Utilities Commission
Open Access Transmission Tariff (OATT) Amendments

For further information, please contact Janet Fraser at 604-623-4176.

Yours sincerely,

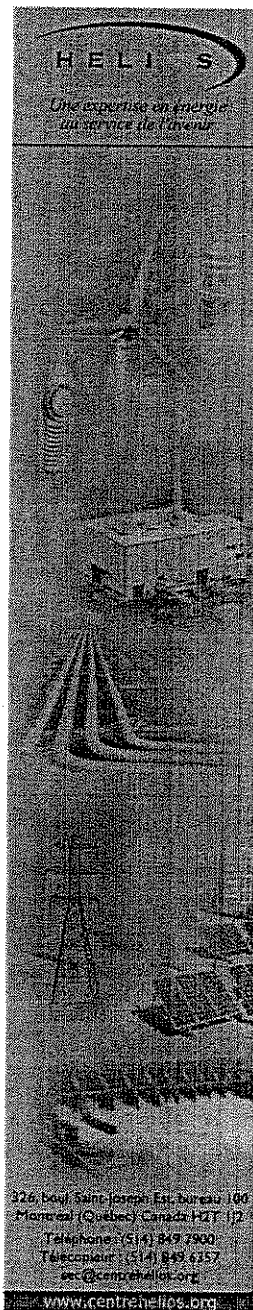


Joanna Sofield
Chief Regulatory Officer

gd/ma

Enclosures (6)

- c. BCOAPO
Capital Power Corporation
- Cargill
- Enmax
- IPPEC
- JIESC
- Morgan Stanley
- NorthPoint
- Powerex
- Teck Metals
- TransAlta



La modification des Tarifs et conditions en fonction de l'Ordonnance 890

Témoignage expert de Philip Raphals

pour le RNCREQ et UC

R-3669-08, phase 2

Régie de l'énergie

Version révisée

le 15 juin 2009

Version ré-révisée

le 23 septembre 2010

La structure, la forme et, en très grande partie, le contenu des Tarifs et conditions de Hydro-Québec TransÉnergie ont été empruntées au *pro forma tariff* de l'ordonnance 888 de la FERC. Les motifs d'adoption d'un tel tarif de transport ont été clairement énoncés dans différents documents officiels de l'époque. Nous avons résumé ces énoncés dans notre témoignage au cours du dossier R-3401-98, comme suit¹ :

The energy policy promulgated by the Québec government in the fall of 1996 announced for the first time that Hydro-Québec would adopt a transmission tariff. It did so in the following terms:

The Act respecting the Régie de l'énergie makes a specific provision enabling the Régie to set or modify tariffs and conditions under which electricity is transmitted, upon the request of Hydro-Québec. This provision makes reference to wheeling activities and extends the jurisdiction of the Régie to these activities. Hydro-Québec will take advantage of this provision.

The initiative taken here by the government will make it possible to respect the reciprocity requirement formulated by the Federal Energy Regulatory Commission, in its April 1996 order. At that time the FERC stipulated that before foreign regions could have access at market prices and on an equal footing with competing American companies, they must first offer equivalent access to their own grids. The provisions included in the *Act respecting the Régie de l'énergie* make the setting-up of such a service possible, thus opening the door for Hydro-Québec to deal on the American market as an electricity trader.² (emphasis added)

The relationship between the transmission tariff and HQUS' PMA [Power Marketer Authorization] application to the FERC was made even clearer in the order-in-council by which the Government of Québec approved HQ's first open access transmission tariff (reg. 652). The government chose to exempt the order from prior publication,³ and justified this exemption in the following terms:

— the new regulatory framework for wholesale electric transmission in the United States will come into force on 1 January 1997;

¹ R-3401-98, Témoignage de P. Raphals, P.A. Bradford et E.O. Disher pour le RNCREQ, pages 4 à 6.

² Government of Québec, *Energy at the Service of Québec: A Sustainable Development Perspective* (1996), p. 57.

³ Under art. 12 of the *Regulations Act*, prior publication of a draft regulation can be dispensed with when the urgency of the situation so requires.

Nous concluons de ce qui précède constater que, plus de deux ans après le dépôt de la requête R-3669-08, cette confusion demeure. Il serait hautement souhaitable de clarifier en audience la position du Transporteur ne demande pas à la Régie de tenir compte, dans ses décisions sur les modifications proposées par rapport au droit de réciprocité qui découle, ou non, de la conformité de ses Tarifs et conditions avec les Ordonnances le pro forma de la FERC, et de l'importance de cette question pour lui et pour Hydro-Québec.

Conséquemment, et sous réserve des représentations ultérieures du Transporteur, nous sommes d'avis que la Régie ne devrait pas approuver une modification sur la base de l'unique motif de la conformité avec les Ordonnances. Une modification ne devrait être acceptable que si, au-delà de la conformité, elle améliore concrètement le régime réglementaire applicable au Transporteur et est d'intérêt public.

5 Le plafond sur le prix de cession ou de revente de capacité de transport

5.1 Mise en contexte

L'art. 23.1 des *Tarifs et conditions*, emprunté du *pro forma tariff* de l'Ord. 888, impose un prix plafond sur toute cession ou revente de capacité de transport de point à point²⁴.

- 16 L'article 23.1 des *Tarifs et conditions* prévoit déjà la revente de capacité par le
17 client (revendeur) à un autre client admissible (cessionnaire). On y prévoit que
18 le prix payé ne peut excéder le plus élevé des montants suivants : (i) le prix
19 initial payé par le revendeur; (ii) le tarif maximum du Transporteur au moment
20 de la cession ou revente; ou (iii) le coût d'opportunité du revendeur, plafonné
21 au coût d'expansion du Transporteur.

Plus précisément, HQT propose la modification suivante à l'art. 23.1 :

23.1 Procédures de cession ou de transfert du service : Un client du service de transport peut vendre, céder ou transférer tout ou partie de ses droits en vertu de sa convention de

²⁴ HQT-1, doc. 1, p. 19.

service. In TAPS' view, costs associated with hoarding will not encourage resale if withholding profitably raises prices in the secondary market. (Ord. 890-A)

La FERC n'a pas retenu ces arguments, mais il est ~~utile~~important de préciser pourquoi. Elle souligne d'abord que ce n'est pas seulement les affiliés d'un transporteur qui peuvent exercer ces stratégies, mais n'importe quel client du service de transport. Surtout, la FERC refuse de distinguer entre différentes classes de clients parce **qu'elle a déjà constaté que le marché secondaire pour la capacité de transport est suffisamment concurrentiel.**

404. While it is true that lifting the price cap for reassignments of capacity could provide an economic incentive for the transmission provider's merchant function or its affiliates to acquire transmission capacity in an attempt to exercise market power, the same is true for any customer. Under the Standards of Conduct, affiliated and unaffiliated customers have equal access to transmission-related information and, through the OASIS, equal opportunity to acquire primary transmission capacity. Thus, any customer could engage in speculative purchasing in an attempt to gain market power. ...

406. Because the Commission has found the secondary market for transmission capacity to be sufficiently competitive, it would not be appropriate to distinguish between classes of customers reselling their capacity. (890-A)

Finalement, par l'Ord. 890-A, la FERC rend provisoire la suppression du prix plafond. Plus précisément, elle indique que cette suppression se limite à la période nécessaire pour accumuler deux années complètes de données (soit du 1^{er} mai 2008 au 1^{er} mai 2010), après quoi son *staff* déposera une étude sur l'expérience.

In Order No. 890, the Commission directed staff to closely monitor the quarterly reassignment-related data submitted by transmission providers to identify any problems in the development of the secondary market and to prepare a report on staff's findings for the Commission within 6 months of the receipt of two years worth of data, i.e., by May 1, 2010. Upon further consideration, we conclude that it is most appropriate to lift the price cap on reassignments of capacity only to accommodate this study period and amend section 23.1 of the pro forma OATT to reinstate the price cap as of October 1, 2010.

Ainsi, le prix plafond sera de nouveau en vigueur à partir du 1^{er} octobre 2010, à moins que la FERC n'en décide autrement.

5.2 Pertinence pour le Québec

De prime abord, il faut souligner que la motivation principale ~~pour~~de la FERC pour cette modification ne trouve pas application au Québec parce que, comme le Transporteur l'a souligné à

plusieurs reprises, les phénomènes de congestion et de sous-investissement, qui sont des problèmes majeurs aux États-Unis, ne l'affectent pas.

Deuxièmement, la Régie ne s'est jamais prononcée sur le degré de compétitivité du marché secondaire du transport au Québec. On ne peut donc pas présumer que, même en suivant la logique de la FERC, il serait approprié de supprimer le plafond de prix pour l'ensemble des catégories de clients. Avant de le faire, la Régie devrait, elle aussi, constater, comme l'a fait la FERC, que la surveillance qu'elle appliquera au marché secondaire sera suffisante pour empêcher tout exercice de *market power*. Par ailleurs, étant donné la différence de taille entre la société Hydro-Québec et ses concurrents au Québec, il est loin d'être évident que le constat de la FERC citée ci-dessus (« *the same is true for any customer* ») trouve application ici.

Troisièmement, Dans nos DDR, nous avons essayé de comprendre la position du Transporteur par rapport au degré de compétitivité du marché secondaire au Québec. Sa réponse est révélatrice :

R4.2. Depuis l'ouverture du réseau de transport au transit de gros en 1997, le Transporteur n'a été mis au fait d'aucune revente à un tiers d'un service de transport fourni par le Transporteur²⁹.

Étant donné qu'il n'existe pas, à toutes fins pratiques, un marché secondaire de transport au Québec, il serait farfelu de prétendre que ce marché est pleinement compétitif. La FERC a pris soin, dans l'Ord. 890-A, de préciser que la suppression du prix plafond a pour unique but d'accommoder la période d'étude de deux ans se terminant le 1^{er} mai 2010. Or, comme société non soumise à la compétence de la FERC, HQ TransÉnergie ne fera pas partie de l'étude en question. De plus, étant donné que la décision finale dans le présent dossier ne sera vraisemblablement pas émise avant l'automne 2009, TransÉnergie aura seulement 6 mois d'expérience à y contribuer.

Par ailleurs, le Transporteur n'a pas démontré que le développement d'un marché secondaire aura des bénéfices pour lui-même, pour ses clients, pour la charge locale ou pour la société québécoise en général. Questionné à cet égard, il répondait de façon très large qu'en général, « l'existence d'un marché secondaire a pour effet de favoriser les échanges entre acheteurs et revendeurs potentiels et

²⁹ HOT-8, doc. 6, p. 8.

tie up capacity that may be needed by other customers. This is because the current policy allows a rollover customer to lock up existing capacity, regardless of whether the rollover customer intends to use that capacity. This reduces the availability of existing capacity for other customers and, in turn, reduces competitive alternatives for customers.

Nous partageons l'avis du Transporteur qu'il y a lieu de retenir la modification proposée par la FERC. D'une part, le droit de renouvellement en vertu des dispositions existantes effectivement crée des obligations non justifiées auprès du Transporteur. D'autre part, il empêche les autres participants d'avoir accès à ces capacités jusqu'à la dernière minute.

Nous recommandons donc à la Régie d'approuver la modification proposée à l'art. 2.2.

Nous partageons l'avis du Transporteur qu'il y a lieu de retenir la modification proposée par la FERC. D'une part, le droit de renouvellement en vertu des dispositions existantes effectivement crée des obligations non justifiées auprès du Transporteur. D'autre part, il empêche les autres participants d'avoir accès à ces capacités jusqu'à la dernière minute.

Nous recommandons donc à la Régie d'approuver la modification proposée dans la première phrase de l'art. 2.2. Toutefois, nous ne formulons pas de commentaire concernant les autres modifications proposées pour cette disposition.

9 Le processus de planification du réseau

9.1 Contexte

Le nouveau OATT *pro forma* qui accompagne les Ordonnances inclut un appendice K qui présente le processus de planification du transporteur. Cette description doit contenir suffisamment de détails pour permettre aux clients de comprendre :

1. le processus de consultation
2. les procédures d'avis et la fréquence anticipée des rencontres
3. la méthodologie, les critères et les processus utilisés pour développer les plans de transport
4. la méthode de divulgation des critères, prémisses et données qui sous-tendent la planification du réseau

5. Les obligations et les méthodes pour permettre aux clients de soumettre des données au transporteur
6. le processus de règlement des différends
7. les procédures du transporteur pour étudier des ajouts de nature économique visant la congestion ou l'intégration de nouvelles ressources
8. les procédures ou principes pertinents de répartition des coûts⁵⁴.

Le Transporteur est d'avis que ces exigences visent principalement à combler la déficience d'investissements en infrastructure de transport aux États-Unis⁵⁵. Étant donné le cadre réglementaire au Québec et le niveau adéquat d'investissement ainsi que l'absence de congestion, il est d'avis qu'il n'y a pas lieu de joindre un processus de planification à ses *Tarifs et conditions*.⁵⁶ Il considère que « la situation au Québec est très différente de la situation aux États-Unis qui a conduit la FERC à imposer l'adoption d'un appendice K⁵⁷. De plus,

Le Transporteur est d'avis que le cadre réglementaire en vigueur au Québec ainsi que les caractéristiques physiques, économiques et organisationnelles en place au Québec dissipent les préoccupations à l'égard de la discrimination induite dans la planification du réseau de transport soulevées au paragraphe 435⁵⁸. (nos soulignés)

Le Transporteur soutient également que l'absence d'un appendice K « n'affecte pas le respect de l'exigence de réciprocité⁵⁹ ». Soulignons que cette réponse semble contredire celles citées à la page **Erreur ! Signet non défini.** 8 ci-dessus. Il serait souhaitable que le Transporteur clarifie dès le début de l'audience ce qu'il entend par « l'exigence de réciprocité ».

Code de champ modifié

⁵⁴ Order 890, para. 602 et pro forma, Attachment K, Original Sheets 162 and 163.

⁵⁵ HQT-1, doc. 1, p. 13.

⁵⁶ Ibid., p. 15.

⁵⁷ HQT-8, doc. 6, p. 18.

⁵⁸ Ibid.

⁵⁹ HQT-8, doc. 3, p. 6.

Enfin, le Transporteur indique qu'il offre déjà une planification ouverte, transparente et coordonnée⁶⁰.

9.2 Les objectifs visés par la FERC

Au paragraphe 425 de l'Ord. 890, la FERC explique que l'absence de coordination, ouverture et transparence créent des occasions de discrimination induite⁶¹. Le Transporteur explique sa compréhension de ce passage comme suit⁶² :

R. 6.3 Le Transporteur comprend bien la remarque de la FERC dans le contexte américain et en résume la portée aux pages 13 et 14 de la pièce HQT-1, Document 1. La présence de plusieurs transporteurs dans une interconnexion aux prises avec de la congestion et des zones de prix variables peut en effet créer des situations où des divergences d'intérêts économiques sont susceptibles de créer des risques potentiels de discrimination. Ceux qui tirent des bénéfices d'une situation de congestion peuvent souhaiter faire échouer les projets d'investissements en transport. Face à une telle situation, une coordination ouverte et mieux encadrée est un moyen qui peut réduire les risques de discrimination et surtout favoriser la réalisation de projets d'investissements en transport lorsque la carence d'infrastructure de transport crée de trop grandes disparités de prix entre les consommateurs. Toutefois, tel qu'exposé dans sa preuve (pièce HQT-1, Document 1, pages 14 et suivantes), la situation au Québec est fort différente et ne nécessite pas le remède proposé par la FERC.

Il est également d'avis que « le cadre réglementaire en vigueur au Québec ainsi que les caractéristiques physiques, économiques et organisationnelles en place au Québec dissipent » ces préoccupations⁶³.

L'interprétation du Transporteur est donc que la FERC se préoccupe surtout des situations où, en « présence de plusieurs transporteurs dans une interconnexion aux prises avec de la congestion et

⁶⁰ HQT-29, doc. 5, p. 3, R1.

⁶¹ « Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory. »

⁶² HQT-8, doc. 6, p. 18.

⁶³ Ibid.

des zones de prix variables », « ceux qui tirent des bénéfices d'une situation de congestion peuvent souhaiter faire échouer les projets d'investissements en transport. »

Il s'agit, à notre avis, d'une interprétation erronée de l'Ordonnance 890. Lu ensemble, cette section indique clairement que la discrimination en question n'est pas du tout celle d'un transporteur qui veut faire échouer des projets de transport qui risquent de réduire les bénéfices qu'il tire d'une situation de congestion, **mais plutôt la discrimination en faveur des ventes d'électricité d'une entité affiliée**, comme le démontrent les passages soulignés des paragraphes 422 à 424 :

422. We do not believe that the existing pro forma OATT is sufficient in an era of increasing transmission congestion and the need for significant new transmission investment. We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner. Although many transmission providers have an incentive to expand the grid to meet their state-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area. For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive. A transmission provider also does not have an incentive to increase the import or export capacity of its transmission system if doing so would allow cheaper power to displace its higher cost generation or otherwise make new entry more profitable by facilitating exports.

423. As the Commission explained in Order No. 888, "[i]t is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves." [note omitted] The court agreed on review of Order No. 888, noting in TAPS v. FERC that "[u]tilities that own or control transmission facilities naturally wish to maximize profit. The transmission-owning utilities thus can be expected to act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers." [note omitted] The Supreme Court in New York v. FERC similarly explained that "public utilities retain ownership of the transmission lines that must be used by their competitors to deliver electric energy to wholesale and retail customers. The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions." [note omitted]

424. The existing pro forma OATT does not counteract these incentives in the planning area because there are no clear criteria regarding the transmission provider's planning obligation. Although the pro forma OATT contains a general obligation to plan for the needs of their network customers and to expand their systems to provide service to point-to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and state commissions. [note omitted] Rather, transmission providers may develop transmission plans with limited or no input from customers or other

stakeholders. There also is no requirement that the key assumptions and data that underlie transmission plans be made available to customers.

425. Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory. This means that disputes over access and discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between transmission providers and their customers for purposes of planning.⁶⁴ The Commission has a duty to prevent undue discrimination in the rates, terms, and conditions of public utility transmission service and, therefore, an obligation to remedy these transmission planning deficiencies. (nos emphases)

Vu de cette façon, il devient évident que **le cadre réglementaire en vigueur au Québec ainsi que les caractéristiques physiques, économiques et organisationnelles en place au Québec ne dissipent aucunement les préoccupations d'une discrimination induite.** Au contraire, les incitatifs pour le Transporteur de discriminer indûment pour avantager les divisions marchandes de sa société-mère demeurent réels, tel que décrits par la Cour d'appel et par la Cour suprême des États-Unis au paragraphe 423 cité ci-dessus.

Ainsi, les arguments présentés par le Transporteur ne réduisent en rien la force de la conclusion principale de la FERC :

Commission Determination

435. In order to limit the opportunities for undue discrimination described above and in the NOPR, and to ensure that comparable transmission service is provided by all public utility transmission providers, including RTOs and ISOs, the Commission concludes that it is necessary to amend the existing pro forma OATT to require coordinated, open, and transparent transmission planning on both a local and regional level. ... (nos soulignés)

Il se peut, bien sûr, que les exigences précises que la FERC a énoncé pour l'Appendice K puissent être modifiées pour refléter le cas particulier du Québec, avec une structure institutionnelle et un cadre réglementaire très différents de ceux des États-Unis. Toutefois, à notre avis, l'analyse que fait

⁶⁴ In our discussion of enforcement issues at section V. E of this Final Rule, we note specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations involving transactions with affiliates. While these specific situations may not directly relate to discrimination in planning, they nevertheless document the continuing incentive of transmission providers to favor themselves and their affiliates in the provision of transmission service.

la FERC sur les possibilités de discrimination qui découlent d'un processus de planification qui n'est ni ouvert ni transparent est très pertinente à notre contexte.

Dans les prochaines sous-sections, nous ~~examineront~~examinerons les éléments principaux de cette exigence.

9.2.1 Coordination

La FERC exige la tenue de rencontres de planification entre les transporteurs, leurs transporteurs avoisinants, les autorités des États, leurs clients et d'autres *stakeholders*, sans en préciser la forme ni la fréquence. L'objectif explicite est d'ouvrir les lignes de communication afin d'éliminer la possibilité de discrimination induite.

a. Coordination

445. In the NOPR, the Commission proposed that transmission providers must meet with all of their transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis. ...

Commission Determination

451. The Commission adopts the coordination principle proposed in the NOPR. Commenters overwhelmingly desire flexibility as to the coordination principle, and as such, we will not prescribe the requirements for coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice requirements, the format, and any other features. We will allow transmission providers, with the input of their customers and other stakeholders, to craft coordination requirements that work for those transmission providers and their customers and other stakeholders.

452. We emphasize that the purpose of the coordination requirement is to eliminate the potential for undue discrimination in planning by opening appropriate lines of communication between transmission providers, their transmission-providing neighbors, affected state authorities, customers, and other stakeholders. Rigid and formal meeting procedures may be one way to accomplish this goal, but there may be other ways as well. For example, a transmission provider could meet this requirement by facilitating the formation of a permanent planning committee made up of itself, its neighboring transmission providers, affected state authorities, customers, and other stakeholders. Such a planning committee could develop its own means of communication, which may or may not emphasize formal meeting procedures. We are more concerned with the substance of coordination than its form.

9.2.2 Ouverture

La FERC se prononce clairement en faveur d'une approche ouverte et inclusive pour le processus de planification du réseau de transport, tout en soulignant l'importance de développer, encore une fois en collaboration avec les parties intéressées, des mécanismes adéquats pour protéger la confidentialité commerciale et les préoccupations reliées à la sécurité nationale. Elle mentionne notamment les ententes de confidentialité et l'accès à l'information protégée par des mots de passe comme des moyens utiles à considérer à cette fin.

Commission Determination

460. The Commission adopts the NOPR's proposal and will require that transmission planning meetings be open to all affected parties including, but not limited to, all transmission and interconnection customers, state commissions and other stakeholders. We recognize that it may be appropriate in certain circumstances, such as a particular meeting of a subregional group, to limit participation to a relevant subset of these entities. We emphasize, however, that the overall development of the transmission plan and the planning process must remain open. We agree with the concerns of some commenters that safeguards must be put in place to ensure that confidentiality and CEII concerns are adequately addressed in transmission planning activities. Accordingly, we will require that transmission providers, in consultation with affected parties, develop mechanisms, such as confidentiality agreements and password-protected access to information, in order to manage confidentiality and CEII concerns.

9.2.3 La transparence

Tel que mentionné plus haut, la FERC requiert que les transporteurs divulguent à l'ensemble de leurs clients ainsi qu'aux autres parties intéressées les critères, prémisses et données qui sous-tendent leur planification, ainsi que des informations à jour sur les différents ajouts et modifications ainsi que les plans et études en relation avec eux.

La FERC a également statué que, lorsque des ressources autres que la production peuvent fournir des fonctions étudiées dans le cadre du processus de planification, comme par exemple les services complémentaires, les fournisseurs potentiels de tels services devraient pouvoir participer à ce processus au même titre que les autres clients et parties intéressées.

Commission Determination

471. The Commission adopts the NOPR's proposal and 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. This information should enable customers, other stakeholders, or an independent third party to replicate the results of planning studies and thereby reduce the incidence of after-the-fact disputes regarding whether planning has been conducted in an unduly discriminatory fashion. We note, however, that transmission providers cannot be expected to fulfill these planning obligations unless non-public utility transmission providers that participate in the planning process make similar information available and, for the reasons set forth above, we fully expect that they will do so. We believe that the same safeguards developed as discussed above regarding the openness principle, such as confidentiality agreements and password protected access to information, will adequately protect against inappropriate disclosure of confidential information or CEII.

472. The Commission also 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. It is important that the Commission, stakeholders, neighboring transmission providers, and affected state authorities have ready access to this information in order to facilitate coordination and oversight. To the extent any such information is confidential or consists of CEII, the transmission provider can implement the safeguards suggested above.

479. Finally, several commenters assert that demand response resources should be considered in transmission planning. [note omitted] Some commenters note that certain regions currently are in the process of incorporating demand response into their transmission planning processes. [note omitted] Demand resources currently provide ancillary services in some regions, and this capability is in under development in some others. [note 273⁶⁵] We therefore find that, where demand resources are capable of providing the functions assessed in a transmission planning process, and can be relied upon on a long-term basis, they should be permitted to participate in that process on a comparable basis. [note omitted] This is consistent with EPAct 2005 section 1223.

⁶⁵ See Staff Report: Assessment of Demand Response & Advanced Metering at 97-100 (Docket Number AD-06-2-000) (Demand Response Report), available at http://www.ferc.gov/legal/staff-reports/staffreports/demandresponse.pdf#xml=http://search.atomz.com/search/pdfhelper.tk?sp_o=1,100000,0.

9.2.4 Échanges d'information

Dans le NOPR, la FERC avait proposé que les clients du service de transport aient à soumettre des renseignements sur leurs besoins futurs. Elle a aussi proposé que les participants du marché aient l'occasion de prendre connaissance et de commenter des versions préliminaires du plan de transport.

Finalement, la FERC précise au paragraphe 488 que l'objectif est de fournir aux clients et aux parties intéressées la possibilité de participer avec les transporteurs au processus de planification, et non seulement d'avoir accès aux informations de base.

d. Information Exchange

480. In the NOPR, the Commission proposed that network transmission customers be required to submit information on their projected loads and resources on a comparable basis (e.g., planning horizon and format) as used by transmission providers in planning for their native load. The Commission further proposed that point-to-point customers be required to submit any projections they have of a need for service over that planning horizon and at what receipt and delivery points. The Commission sought comment on whether specific requirements should be adopted for this information exchange. [note omitted] The Commission also stated that transmission providers must allow market participants the opportunity to review and comment on draft transmission plans.

...

Commission Determination

486. The Commission adopts the information exchange principle as to both network and point-to-point transmission customers. Accordingly, we will require transmission providers, in consultation with their customers and other stakeholders, to develop guidelines and a schedule for the submittal of information. In order for the Final Rule's planning process to be as open and transparent as possible, the information collected by transmission providers to provide transmission service to their native load customers must be transparent and, to that end, equivalent information must be provided by transmission customers to ensure effective planning and comparability. We clarify that the information must be made available at regular intervals to be identified in advance. Information exchanged should be a continual process, the frequency of which should be addressed in the transmission provider's compliance filing required by the Final Rule. However, we expect that the frequency and planning horizon will be consistent with ERO requirements.

487. We also believe that it is appropriate to require point-to-point customers to submit any projections they have of a need for service over the planning horizon and at what receipt and delivery points. We believe that any good faith projections of a need for service, even though they may not yet be subject to a transmission reservation, may be useful in transmission planning as they may, for example, provide planners with likely scenarios for new generation

development. If the point-to-point customers do not submit such projections, then the transmission provider cannot later be faulted for failing to consider planning scenarios that might have taken into account reasonable projections of future system uses that were not the subject of specific service requests. To the extent applicable, transmission customers also should provide information on existing and planned demand resources and their impacts on demand and peak demand. In addition, stakeholders should provide proposed demand response resources if they wish to have them considered in the development of the transmission plan.

488. Lastly, in response to the concerns of some commenters, we emphasize that the transmission planning required by this Final Rule is not intended, as discussed earlier, to be limited to the mere exchange of information and then review of transmission provider plans after the fact. The transmission planning required by this Final Rule is intended to provide transmission customers and other stakeholders a meaningful opportunity to engage in planning along with their transmission providers. At the same time, we emphasize that this information exchange relates to planning, not other studies performed in response to interconnection or transmission service requests.

9.2.5 Comparabilité

La FERC exige des transporteurs que leurs propres intérêts (et, implicitement, ceux de leurs entités affiliées) soient traités sur un plan d'égalité avec ceux de leurs clients. Elle exige notamment que, ~~lorsque approprié~~ lorsqu'appropriées, les ressources autres que la production soient traitées sur un pied d'égalité avec les ressources traditionnelles.

Commission Determination

494. The Commission adopts the NOPR's proposal as to the comparability principle and will require the transmission provider, after considering the data and comments supplied by customers and other stakeholders, to develop a transmission system plan that (1) meets the specific service requests of its transmission customers and (2) otherwise treats similarly-situated customers (e.g., network and retail native load) comparably in transmission system planning. [note omitted] Further, we agree with commenters that customer demand resources should be considered on a comparable basis to the service provided by comparable generation resources where appropriate.

495. We are specifically requiring a comparability principle to address concerns, such as those raised by commenters, that transmission providers continue to plan their transmission systems such that their own interests are addressed without regard to, or ahead of, the interests of their customers. Comparability requires that the interests of transmission providers and their similarly-situated customers be treated on a comparable basis. In response to the concerns expressed by several commenters, we emphasize that similarly-situated customers must be treated on a comparable basis, not that each and every transmission customer should be treated the same. [note omitted].

9.3 Observations

Déjà dans notre rapport d'expertise enau dossier R-3401-98, présenté en février 2001, nous avons soulevé la problématique de la participation des parties intéressées dans les processus de planification, en résumant les pratiques déjà en place à l'époque dans plusieurs juridictions (California, Alberta, PJM, New England et New York)⁶⁶. Dans chacune de ces juridictions, il existait déjà un processus de planification ouvert, à différents degrés, à la participation des parties intéressées.

L'extrait suivant résume ces processus :

10.3.2. Stakeholder involvement in transmission planning processes

While formal procedures to evaluate non-transmission alternatives are not universal, it is standard practice for the transmission planning process to include interested parties other than the utility, and transmission plans and related documents are treated as public documents. Thus:

- in California, each utility prepares its own transmission plan in close coordination with the Cal-ISO staff and interested electric market participants;¹³⁴
- in Alberta, transmission issues are debated at the Transmission Planning Committee, which is open to all stakeholders;¹³⁵
- in the PJM region, the Transmission Expansion Advisory Committee includes environmental and consumer advocacy groups, as noted above;

⁶⁶ Raphals, Bradford et Disher, voir note 1, pages 71 à 81.

- In New England, the Transmission Expansion Planning Process is conducted by ISO-NE (which in turn is under the direction of an independent board without ties to market participants), together with the transmission owners. The resulting five-year NEPOOL Transmission Plan lists projects which have received NEPOOL review and approval, as well as those which have not. Other stakeholders can comment on the draft Plan through the NEPOOL Reliability Committee, one of three standing committees that provide for interaction between ISO-NE and market participant stakeholders. Additional stakeholder input can be provided on a less formal basis through the ISO's Advisory Committee, that is open to public interest groups and state agency representatives.
- In New York, the Transmission Planning Advisory Subcommittee, which provides guidance to the NYISO transmission planning staff, is open to members and eligible customers of the ISO; others may participate as guests. The New York ISO publishes an annual long-term Transmission Plan, and maintains a constantly updated "transmission and interconnection study queue" on its website

(<http://www.nyiso.com/services/planning.html>), listing all the studies that have been requested of the ISO for potential upgrades, additions and interconnections.

¹⁵² ESBi Alberta Ltd., *Alberta Interconnected Electric System: Transmission Development Plan 2000-2009*, December 1999, p. 5.

¹⁵³ ESBi Alberta Ltd., *Transmission Development Plan 2000-2010*, p. 15.

¹⁵⁴ PG&E, *Electric Transmission Grid Expansion Plan for the Years 2001-2005*, p. 3.

¹⁵⁵ ESBi Alberta Ltd., *Transmission Development Plan 2000-2010*, p. 6.

Cet extrait démontre que les processus ouverts et transparents qu'exige maintenant la FERC de l'ensemble des transporteurs sous sa compétence faisait/faisaient déjà partie, en grande mesure, des pratiques des transporteurs les plus avancés-avant-gardistes. Ce qui est nouveau, dans l'Ord. 890, c'est la détermination qu'un tel processus est essentiel pour éviter la discrimination induite, qui devient donc obligatoire.

9.4 Les rapports de Judah Rose

M. Rose a déposé deux rapports concernant le processus de planification d'HOT. Dans son premier rapport (HOT-12, doc. 1, ci-après son « Rapport »), il présente de façon sommaire son point de vue à l'effet qu'il n'est pas nécessaire ni opportun d'ajouter l'Annexe K de la FERC aux processus de planification déjà en vigueur au Québec. Dans son deuxième rapport, présenté en guise d'une réponse aux DDR, il présente ses raisons en plus de détail (ci-après ses « Réponses »)⁶⁷.

⁶⁷ HOT-8, doc. 6.1.

Dans son Rapport, M. Rose identifie deux raisons principales pour les exigences de la FERC à l'égard de l'Annexe K : 1) les déficiences des réseaux de transport américains (notamment la congestion et un niveau inadéquat d'investissement), et 2) pour éviter de la discrimination induite à l'égard des compagnies non affiliées⁶⁸. Il affirme, avec raison, que le réseau d'HQT ne souffre pas ni d'une congestion soutenue ni d'un niveau inadéquat d'investissement. Il affirme également que le Québec offre déjà un processus de planification qui est coordonné, ouvert et transparent⁶⁹, justifiant cette affirmation en référant à une série de documents sommaires préparés par HQT (HQT-15 à HQT-27). Par contre, son rapport ne traite pas de la deuxième raison invoquée, potentiellement pour éviter la discrimination induite à l'égard des compagnies non affiliées.

Le Transporteur affirme également qu'il offre déjà une planification ouverte, transparente et coordonnée, en précisant que « la mise en œuvre de ces principes ne découle pas du texte proposé des *Tarifs et conditions*, mais plutôt de mesures déjà en place », tel que décrites dans les Réponses⁷⁰.

Les perceptions de M. Rose à l'égard des processus de consultation au Québec ne sont pas entièrement valides. Pour mentionner quelques exemples :

- Il affirme que TransÉnergie présente un plan stratégique à une commission parlementaire, et que des personnes intéressées peuvent participer à ce processus⁷¹. Il s'agit du *Plan stratégique d'Hydro-Québec*, et non pas de TransÉnergie. Par ailleurs, sauf quelques rares exceptions, la Commission de l'économie et du travail n'entend pas de mémoires du public. Par ailleurs, le *Plan stratégique d'Hydro-Québec* ne contient pas un niveau de détail suffisant sur la planification de transport pour rendre ce processus utile et répondre de manière satisfaisante aux objectifs recherchés par la FERC.
- Il insiste, avec raison, sur le fait que les audiences de la Régie en vertu de l'art. 73 permettent la participation du public⁷². Toutefois, la Régie s'est exprimée à plusieurs

⁶⁸ HQT-12, doc. 1, pages 7 et 8, et HQT-8, doc. 6.1, paragraphes 2b, 8 et 9.

⁶⁹ HQT-8, doc. 6.1, para. 37.

⁷⁰ HQT-29, doc. 5, p. 7, R6b.

⁷¹ Ibid., para. 25.

⁷² Ibid., pages 7 à 10.

reprises à l'effet qu'une telle audience n'est pas le forum approprié pour faire l'étude de la planification du Transporteur.

- L'examen d'un projet proposé par le BAPE n'est pas non plus l'équivalent d'un processus ouvert de planification tel que l'envisage l'Ord. 890, parce qu'il n'a lieu que bien après que le processus de planification a eu lieu. L'essence même de l'Annexe K est de permettre la participation du public avant que les décisions de planification ne soient prises. Des audiences publiques sur un projet de transport — soit devant la Régie (art. 73), soit devant le BAPE (mitigation des impacts environnementaux) ne répondent aucunement aux fins recherchées par la FERC avec son Annexe K.

Notons par ailleurs que des processus d'approbation des projets, tant sur le plan énergétique qu'environnemental, existent également aux États-Unis, ce qui n'a pas empêché la FERC d'exiger l'Annexe K pour l'ensemble des services publics sous sa compétence.

Par ailleurs, bien qu'il identifie les deux raisons précitées pour l'ajout de l'Annexe K au *pro forma* de la FERC, sa preuve se limite à discuter seulement la première.

Donc, sa conclusion principale à l'effet que la Régie n'a pas à résoudre les problèmes américains fait uniquement référence aux problèmes de congestion et de sous-investissement, et ne prend aucunement en compte la question de la discrimination induite. En fait, il ne présente aucun argument sérieux pour démontrer que le réseau québécois est à l'abri de cette problématique.

M. Rose a sans doute raison d'affirmer que la FERC s'intéresse aux problématiques de congestion et de sous-investissement dans les réseaux de transport, et que ces préoccupations n'ont peu ou pas d'importance au Québec. Cela dit, il importe de se rappeler que l'empêchement de la discrimination induite en faveur des affiliées est la problématique qui est au cœur de la démarche entreprise par la FERC avec l'Ord. 888 et qui continue maintenant avec les Ordonnances 890 et al., comme l'indique par exemple le premier paragraphe de l'Ord. 890 :

1. This Final Rule addresses and remedies opportunities for undue discrimination under the pro forma Open Access Transmission Tariff (OATT) adopted in 1996 by Order No. 888. This landmark rulemaking fostered greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service. In the ten years since Order 888, however, the Commission has found that the OATT contains flaws that undermine realizing its core objective of remedying undue discrimination. In the Notice of Proposed Rulemaking (NOPR) issued on May 19, 2006, the Commission proposed to remedy those flaws. After receiving approximately 6,500 pages of comments from close to 300 parties, we now take final action. We highlight below the most critical reforms being adopted today.

Le Transporteur le résume ainsi :

Le 16 février 2007, cette dernière [la FERC] a publié l'ordonnance no 890, qui a modifié ses règlements et le tarif *pro forma* afin, entre autres, de le raffermir pour qu'il atteigne son objectif initial de remédier à la discrimination induite, et d'offrir des règles plus explicites pour réduire les occasions de discrimination⁷³.

Par ailleurs, il est clair que, malgré le fait que le public puisse participer à certaines étapes du processus d'approbation des projets de transport, notamment les audiences du BAPE et celles de la Régie en vertu de l'art. 73 LRE, le processus de planification de transport d'HQT n'est ni ouvert ni transparent. En effet, ni les utilisateurs non affiliés du réseau, ni les différents regroupements de la société civile représentant des intérêts affectés par les projets d'HQT n'ont le droit de connaître le Plan de transport d'HQT dans ses détails, ni encore moins de se faire entendre avant que les décisions ne soient prises par HQT.

Dans ses Réponses, M. Rose présente ses observations à l'effet que la planification de TransÉnergie est déjà ouverte, transparente et coordonnée. Il affirme qu'aucune modification n'est nécessaire afin d'offrir de l'accès ouvert et comparable à son réseau⁷⁴. Il exprime l'opinion qu'une conformité « section by section or line by line » n'est pas requise afin de rencontrer les « reciprocity requirements for open and comparable access », notamment en raison de l'importance de la flexibilité dans l'Ord. 890⁷⁵.

Or, quoiqu'il existe certainement des sections de l'Ord. 890 où la FERC démontre de la flexibilité, on ne peut qualifier l'Ordonnance de cette façon de manière générale. Comme nous l'avons déjà vu, dans un grand nombre d'aspects, l'Ord. 890 représente une réduction de la flexibilité par rapport à l'Ord. 888, par exemple dans la désignation des ressources, le calcul de l'ATC et la fixation des tarifs pour les services de compensation des écarts de livraison et de réception. Selon notre lecture des sections des Ordonnances touchant la planification du transport, il est clair que, quoique la FERC demeure flexible quant aux **moyens** utilisés pour respecter ses exigences quant à la planification du transport, elle ne démontre pas de flexibilité quant à ces exigences elles-mêmes.

⁷³ HT-1, doc. 1, p. 9.

⁷⁴ Réponses, para. 95.

⁷⁵ Ibid., para. 94.

En effet, l'Ord. 890 énonce clairement la nature de la flexibilité qu'elle comporte. Si un transporteur considère que son processus actuel de planification est en conformité avec les principes énoncés dans l'Ordonnance, il doit le décrire dans son OATT et expliquer à la FERC dans un *compliance filing* pourquoi les divergences sont justifiées. Dans les deux cas, la FERC précise que le processus doit être documenté dans une annexe à son OATT.

437. Accordingly, each public utility transmission provider is required to submit, as part of a compliance filing in this proceeding, 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. Under either of these approaches, the process must be documented as an attachment to the transmission provider's OATT.

La section la plus imposante des Réponses s'intitule « Measures in Place Ensuring Transparency » (paragraphe 29 à 70, pages 7 à 13). Il s'agit notamment des modalités bien connues des audiences sous l'art. 73, des audiences tarifaires et du BAPE. Il mentionne également le Code de conduite de TransÉnergie, la procédure d'étude d'impact sur le réseau des *Tarifs et conditions*, ainsi que son processus de plaintes, le processus de planification du NPCC, etc.

Pourtant, il est clair que ces modalités et procédures devant diverses institutions ne rencontrent tout simplement pas les exigences minimales décrites par la FERC.

Ainsi, le processus existant ne permet pas aux participants du marché de savoir si le plan retenu est discriminatoire ou non :

424. The existing pro forma OATT does not counteract these incentives in the planning area because there are no clear criteria regarding the transmission provider's planning obligation. Although the pro forma OATT contains a general obligation to plan for the needs of their network customers and to expand their systems to provide service to point- to-point customers, there is no requirement that the overall transmission planning process be open to customers, competitors, and state commissions. [note omitted] Rather, transmission providers may develop transmission plans with limited or no input from customers or other stakeholders. There also is no requirement that the key assumptions and data that underlie transmission plans be made available to customers.

425. Taken together, this lack of coordination, openness, and transparency results in opportunities for undue discrimination in transmission planning. Without adequate coordination and open participation, market participants have no means to determine whether the plan developed by the transmission provider in isolation is unduly discriminatory. This means that disputes over access and discrimination occur primarily after-the-fact because there is insufficient coordination and transparency between

transmission providers and their customers for purposes of planning.⁷⁶ The Commission has a duty to prevent undue discrimination in the rates, terms, and conditions of public utility transmission service and, therefore, an obligation to remedy these transmission planning deficiencies. (nos emphases)

Elle ne permet pas non plus aux clients ni aux autres intéressés de participer avec le Transporteur à l'élaboration de son Plan de transport.

445. In the NOPR, the Commission proposed that transmission providers must meet with all of their transmission customers and interconnected neighbors to develop a transmission plan on a nondiscriminatory basis.

451. The Commission adopts the coordination principle proposed in the NOPR. Commenters overwhelmingly desire flexibility as to the coordination principle, and as such, we will not prescribe the requirements for coordination, such as the minimum number of meetings to be required each year, the scope of the meetings, the notice requirements, the format, and any other features. We will allow transmission providers, with the input of their customers and other stakeholders, to craft coordination requirements that work for those transmission providers and their customers and other stakeholders.

452. We emphasize that the purpose of the coordination requirement is to eliminate the potential for undue discrimination in planning by opening appropriate lines of communication between transmission providers, their transmission-providing neighbors, affected state authorities, customers, and other stakeholders. Rigid and formal meeting procedures may be one way to accomplish this goal, but there may be other ways as well. For example, a transmission provider could meet this requirement by facilitating the formation of a permanent planning committee made up of itself, its neighboring transmission providers, affected state authorities, customers, and other stakeholders. Such a planning committee could develop its own means of communication, which may or may not emphasize formal meeting procedures. **We are more concerned with the substance of coordination than its form.**

Le processus de planification du réseau, tel qu'il prévaut actuellement, ne comporte pas de coordination telle que décrite par la FERC. Il en est de même pour les autres principes décrit à la section 9.2 ci-dessus. Une lecture attentive des passages cités démontre que le système actuel ressemble, au mieux, à celui qui prévalait aux États-Unis avant l'ord. 890. En fait, dans les régions

⁷⁶ In our discussion of enforcement issues at section V. E of this Final Rule, we note specific situations in which transmission providers have agreed to resolve staff allegations that they engaged in OATT violations involving transactions with affiliates. While these specific situations may not directly relate to discrimination in planning, they nevertheless document the continuing incentive of transmission providers to favor themselves and their affiliates in the provision of transmission service.

avant un ISO ou un RTO, le niveau de consultation sur les plans de transport même avant l'Ord. 890 était déjà de loin supérieur au système actuel au Québec, comme le démontre notre preuve en R-3401-98, citée à la section 9.3 ci-dessus.

Quoiqu'on puisse prétendre que les pratiques en Californie, en PJM ou dans le Nord-Ouest américain n'ont pas beaucoup de pertinence au Québec, on ne peut soutenir que ce soit le cas pour New York et pour la Nouvelle-Angleterre, où se situent les partenaires commerciaux principaux d'Hydro-Québec.

Pour cette raison, dans la prochaine section nous examinerons brièvement les processus de planification de transport en Nouvelle-Angleterre, avant et après l'Ord. 890.

9.5 Planification des réseaux de transport dans la Nouvelle Angleterre

Depuis l'an 2000, l'Independent System Operator New England (ISO-NE) est responsable pour la planification du réseau de transport de la région. Le premier Regional Transmission Expansion Plan a été publié en 2001.

Dans le processus menant à l'adoption de ce plan, un comité avisier a été créé, le Transmission Expansion Advisory Committee (TEAC). Pour participer à ce comité, ISO-NE a sollicité les membres des différents comités de NEPOOL et des régulateurs en matière d'énergie et d'environnement, ainsi que une panoplie de groupes d'intérêt public (société civile).

Un autre comité, le Transmission Planning Committee (TPC), comportait des représentants des sept propriétaires des lignes de transport (Transmission Owners). Ce comité a été créé pour fournir de l'expertise technique et des données pour la préparation du plan, ainsi que les ressources techniques nécessaires aux études de fiabilité et de l'adéquation des ressources dans la région.

Ainsi, la Nouvelle-Angleterre bénéficie d'un processus de planification ouvert depuis l'an 2000.

Ce système a continué d'évoluer. En 2007, le Planning Advisory Committee (PAC) — toujours ouvert à la participation par toute entité intéressée — continue de jouer un rôle important dans le processus de planification :

12.1 Status of the Planning Process

The successful operation of the system during the 2007 peak-load periods demonstrated, in part, how proper system planning can help ensure adequate capacity and transmission

capability. RSP07 [Regional System Plan 2007] and related planning studies continue to benefit from an open stakeholder planning process on a regional and interregional basis. Stakeholders, particularly members of the PAC, provide valuable input on the RSP, including the scope of work, draft results, and final draft plans, which are subject to ISO/RTO approval.⁷⁷ (nos soulignés)

Ce processus a été décrit par le pdg de l'ISO-NE comme suit :

How does the process work? The RSP is a comprehensive assessment made up of numerous studies and analyses of the region's bulk electric power system that identifies the location and nature of projected system needs. ISO New England also identifies system problems by conducting technical transmission planning studies with input and analytical assistance from the transmission owners. The system plan is updated annually to reflect both market responses and changes in system or market conditions. Load growth, resource additions and retirements, timing of transmission upgrades, new technologies, and regulatory developments are all examples that have a potential to impact system performance.

In the planning process, ISO New England uses a power system model that includes all generators, transmission facilities, and loads. Simulations address physical issues such as thermal loading, minimum voltage, voltage regulation, transient stability, dynamic oscillations, harmonics and short circuit interrupting capability.

Transparency and feedback are an important part of the planning process. ISO New England conducts and directs studies with input and review from the Planning Advisory Committee (PAC). The PAC is open to any interested party and is composed of a wide variety of regional stakeholders, including market participants, governmental representatives, state agencies, representatives of local communities and consultants. The PAC meets regularly throughout the year. ISO New England posts the meeting minutes and presentations on its Web site. Seven meetings were held throughout New England during the 2004 process. We also solicit input via a public meeting conducted each year by the ISO New England Board of Directors before approval of the annual plan.⁷⁸ (nos soulignés)

L'Attachment K de l'ISO-NE, en vigueur depuis 2008, représente une évolution d'un système de participation publique dans la planification du réseau de transport qui existait depuis plusieurs années. Quoique, dans l'Ord. 890, la FERC ait exigé que l'ensemble des transporteurs, y compris les ISO et les RTO, déposent un Attachment K, il est généralement compris que les exigences retenues par la FERC reflètent, en grande partie, les pratiques déjà en vigueur dans les ISO/RTO les plus avant-gardistes, dont notamment l'ISO-NE. Ainsi, l'Attachment K de l'ISO-NE ne représente pas un changement majeur par rapport à ce qui l'a précédé.

⁷⁷ ISO-NE 2007 Regional System Plan, p. 115.

⁷⁸ http://www.electricenergyonline.com/?page=show_article&mag=30&article=241. Sans date, probablement de 2006.

9.6 La planification du réseau de transport en Colombie-Britannique

9.6.1 Contexte

Dans son premier Rapport (à la page 18), M. Judah Rose décrit les réponses d'autres services publics canadiens aux exigences de la FERC par rapport à la planification du transport comme suit:

- 8 Q. WHAT HAS BEEN THE RESPONSE OF CANADIAN UTILITIES TO
9 ATTACHMENT K?
10 A. No Canadian utility has filed an Attachment K. New Brunswick has filed a brief
11 Attachment K that at best addresses one area; I do not believe it is even close to
12 being in compliance with Attachment K (see Exhibit JLR-4).

Déjà au moment de la rédaction de ce rapport, le British Columbia Transmission Corporation (BCTC) avait soumis à la British Columbia Utilities Commission des amendements à son OATT pour s'harmoniser avec l'Ord. 890, dont notamment un Attachment K (déposé le 21 novembre 2008). Cela a été accepté par la BCUC dans sa décision du 10 septembre 2009⁷⁹.

Étant donné les grandes similarités entre les contextes énergétiques du Québec et de la Colombie-Britannique, le choix de la BCTC (anciennement la division transport de BC Hydro) de procéder à l'implantation d'un processus de planification de transport qui réponde directement aux exigences de la FERC est pertinent à nos réflexions.

Rappelons que le contexte énergétique en Colombie-Britannique est très similaire à celui du Québec, particulièrement en relation avec les éléments auxquels fait référence M. Rose afin de distinguer la situation du Québec de celle des États-Unis. Ainsi :

- Le secteur de l'électricité est dominé par une société d'État, avec une grande prédominance hydraulique.

⁷⁹ BCUC, Decision, BCTC and Amendments to the OATT, 10 septembre 2009.

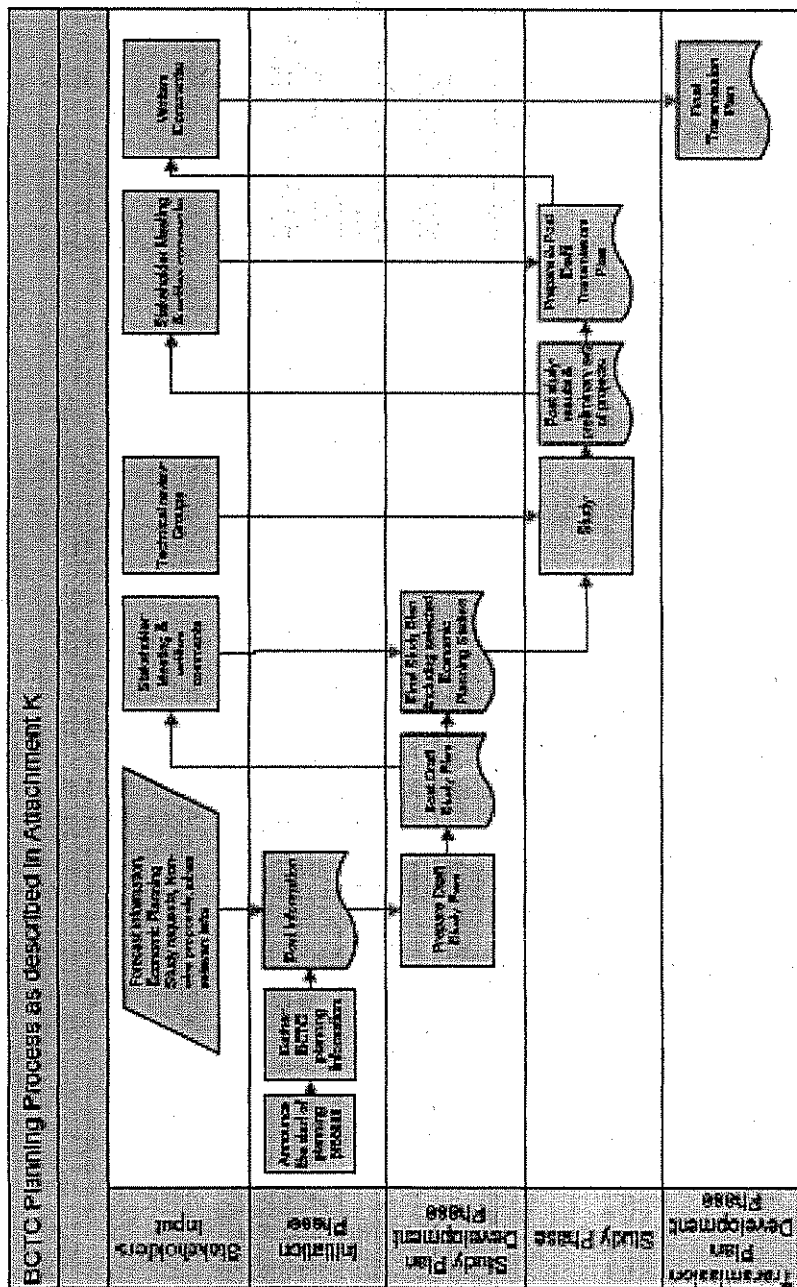
- Étant donné que la société d'État est propriétaire et gestionnaire de la vaste majorité des lignes électriques, le problème de coordination entre plusieurs petits services publics ne se présente pas.
- Étant donné que la vaste majorité de la production est hydraulique et contrôlée par une société d'État, le problème de congestion n'existe pas ou est d'ampleur limité, et
- Le transporteur n'est pas soumis à la compétence de la FERC, mais a néanmoins un intérêt à se conformer à ses exigences, afin de faciliter l'accès aux marchés américains de son affilié.

Dans ce même contexte, la BCTC a pourtant décidé de mettre en place un processus de planification ouvert et transparent, en adoptant un Attachment K basé sur l'Ord. 890. L'Attachment K de la BCTC devient par ce fait même un modèle très pertinent pour TransÉnergie, dans la mesure où la Régie détermine qu'il y a lieu de se doter d'un tel processus.

9.6.2 L'Attachment K de la BCTC

Un graphique qui démontre le cheminement du processus de l'Attachment K du BCTC est présenté à la page suivante. Le texte de son Attachment K est joint aux présentes comme Annexe 3.

Figure 3-1. BCTC Planning Process in Proposed Attachment K



Ce processus implique la participation des intervenants (*stakeholders*) à trois phases de la planification : la préparation d'un plan d'études, l'exécution des études, et la préparation d'un plan de transport. À chacune de ces étapes, les intervenants jouent un rôle consultatif, mais la BCTC demeure l'unique responsable des choix finaux.

9.6.3 Phase d'initiation

Dans la phase d'initiation, la BCTC convoque des parties intéressées et affiche sur son site internet les informations pertinentes, dont notamment les suivantes :

- Le guide de planification (*Planning Manual*) de la BCTC,
- Les données utilisées pour ses études de planification, dont notamment ses données de base (*base case data*),
- Son dernier Plan d'actifs (*Capital Plan*), y compris des rapports à jour sur l'état du réseau
- Le statut actuel des projets d'ajouts au réseau en cours
- Les demandes de service de transport et d'interconnexion reçues, ainsi que toute étude et entente en relation à ces demandes, et
- Informations reçues des clients de transport, tenant compte des procédures pour la protection d'information confidentielle.

À cela s'ajoutera, au fur et mesure, les études et plans développés pendant le processus.

9.6.4 Phase de développement du plan d'étude (*Study Plan Development Phase*)

En se basant sur l'ensemble de cette information, la BCTC prépare et affiche son plan préliminaire des études (*Draft Study Plan*), y compris :

- Besoins et opportunités potentielles (*potential requirements and opportunities*),
- Données et hypothèses de planification,
- Une liste des projets déjà approuvés et leur statut,

- Une liste des études proposées pour rencontrer les besoins et opportunités potentielles, y compris celles prévues en relation avec les demandes de services reçues.
- Un examen des solutions non transport (*non-wires solutions*) pour répondre aux besoins et opportunités potentielles, et
- Critères pour le choix d'études de planification économique (*Economic Planning Studies*).

Une fois le plan préliminaire des études affiché, une rencontre consultative est convoquée, où la BCTC présente :

- Les grandes lignes de ses méthodes, données et hypothèses de planification.
- Les études proposées.
- Le choix proposé des études économiques
- Des Groupes d'étude technique (*Technical Review Groups*) pour des projets spécifiques.
- La période prévue pour des commentaires écrits des intervenants.

Les intervenants ont donc le droit de soumettre des commentaires écrits sur le plan préliminaire, qui seront affichés sur le site internet de planification.

9.6.5 Phase d'études (*Study Phase*)

Une fois les commentaires écrits des intervenants reçus, et en tenant compte de ceux-ci, la BCTC fixe et affiche son Plan final d'études (*Final Study Plan*). Ce Plan doit inclure notamment :

- Une description des besoins et opportunités potentielles
- Les données et hypothèses qui sous-tendent la planification.
- Une liste des études conçues pour rencontrer les besoins et opportunités potentielles, y compris la portée et les livrables de chacune
- Une liste des études économiques (*Economic Planning Studies*) retenues par le Transporteur.

- Un calendrier pour l'ensemble des tâches, et
- Un calendrier des rencontres du *Technical Review Group*.

9.6.6 Comités techniques (*Technical Review Groups*)

Des Comités techniques seront créés afin de fournir un forum ouvert et transparent pour permettre aux intéressés de prendre connaissance et de fournir du *feedback* au Transporteur à l'égard des alternatives à la planification (*planning alternatives*) pour un besoin ou opportunité identifiée par le Transporteur. En même temps, il devrait permettre au Transporteur de mieux connaître les préoccupations des intéressés à l'égard d'un tel projet. Ce comité joue un rôle consultatif.

9.6.7 Phase de développement du plan de transport (*Transmission Plan Development Phase*)

Une fois affiché le Plan final d'études, le Transporteur procède à l'exécution des études y identifiées, afin de produire un ensemble préliminaire des projets pour rencontrer les besoins et opportunités identifiés.

Il est notamment précisé dans l'Attachment K que, en exécutant ses études, le Transporteur tiendra compte des solutions basées tant sur la gestion de la demande que sur la production additionnelle sur une base d'égalité avec les solutions de nature transport.

Par ailleurs, le Transporteur doit développer des critères de planification, qui seront intégrés dans son Guide de planification, qui précise comment les solutions transport et non-transport seront considérés sur un pied d'égalité dans les études.

Une fois les études terminées, le Transporteur affiche les résultats des études et sa liste préliminaire des projets, et organise une rencontre de consultation à cet égard, suite à laquelle les intervenants peuvent fournir des commentaires par écrit.

Tenant compte de ces commentaires, le Transporteur prépare et affiche son Plan préliminaire de transport, qui décrit les investissements majeurs proposés sur un horizon de 10 ans.

Les intervenants peuvent fournir encore une fois des commentaires écrits. Tenant compte de ces commentaires, le Transporteur élabore son Plan final de transport.

9.7 L'intégration des solutions transport et non transport

Dans son Attachment K, la BCTC s'engage à développer des critères de planification, qui seront intégrés dans son Guide de planification, qui précisent comment les solutions transport et non-transport seront considérés sur un pied d'égalité dans les études.

Quoique cela ne soit pas exigé par la FERC, cette préoccupation est cohérente avec les principes retenus en les Ordonnances. Il est mentionné, par exemple, dans les premiers paragraphes de l'Ord. 890 :

3. Second, the Final Rule will increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent, and coordinated transmission planning process. Transmission planning is a critical function under the pro forma OATT because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives. ... (nos soulignés)

D'autres juridictions partagent également cette préoccupation, qui dépasse les exigences de la FERC mais qui n'est pas pour cela moins importante. La Régie n'étant aucunement obligée de suivre les exigences des Ordonnances de la FERC, lorsqu'elle fixe les Tarifs et conditions du Transporteur, elle n'est pas non plus limitée par ses Ordonnances. Pour l'aider à identifier l'approche à la planification du transport qui convient le mieux au Transporteur, nous allons décrire brièvement des démarches récentes à l'État de Vermont à cet égard.

En 2003, le Vermont Electric Power Company (VELCO), un transporteur, de concert avec Green Mountain Power Corporation (GMP), un service public intégré, ont proposé une série de modifications importantes au réseau de transport du Vermont, afin de répondre à la croissance de la demande, notamment dans le nord-ouest de l'État. Dans son ordonnance dans ce dossier (Docket 6860), le Public Service Board (PSB) du Vermont a approuvé la demande en janvier 2005.

Dans sa demande, VELCO avait analysé la possibilité d'éviter des ajouts au réseau de transport par différentes combinaisons d'investissements en programmes ciblés d'efficacité énergétique et de production localisée dans la région affectée. Notamment, il avait mandaté un consultant pour évaluer le potentiel de réduction de la demande à la pointe dans la région, qui indiquait un potentiel d'environ 200 MW à l'horizon 2012. Toutefois, selon VELCO, toute solution alternative aurait également requis l'installation d'une certaine capacité en production additionnelle dans la région.

Le PSB a approuvé le projet, en soulignant que celui-ci représentait la solution de moindre coût pour répondre aux besoins identifiés avec un niveau acceptable de fiabilité. Il soulignait que le problème majeur était l'identification d'un promoteur pour les centrales requises.

Although unprecedented in Vermont, the efficiency investments appear feasible and desirable. However, the timely availability of the necessary new generating plants and the facilities to fuel them is *at best uncertain*.⁸⁰ (italiques dans l'original)

Pour cela, le PSB blâmait le processus de planification de VELCO, tant à l'égard de ses efforts de prévision de la demande que de sa volonté de considérer l'ensemble de solutions potentielles suffisamment tôt pour permettre leur réalisation.

In a fifth major point, the Board notes that this case has demonstrated significant flaws in the planning processes at VELCO, the entity that owns and manages bulk transmission facilities in Vermont. Those flaws fall into at least two categories: (i) deficiencies in forecasting expected electricity demand on a seasonal and region-wide level, leading to a need to consider and install new facilities closer to the time that they are essential than desirable; and (ii) deficiencies in the early consideration of a range of feasible alternatives (such as focused intense efficiency efforts), leading to the present situation in which transmission construction must be chosen as the least-cost reliability solution, despite the fact that an earlier, greater, effort at efficiency might have opened up alternatives. In order to make sure that this situation does not recur in the future, the Board is opening a new investigation, focused on improving VELCO's forecasting abilities, translating those improvements into information for the rest of society, and re-considering the least-cost planning and implementation responsibilities of VELCO and its owners.⁸¹

Afin d'éviter que cette situation ne se répète dans l'avenir, le PSB a décidé d'ouvrir une nouvelle enquête (Docket 7081):

Notwithstanding these conclusions, we are deeply troubled that, in the present case, we have no viable option but to approve a transmission solution for a reliability problem that might have been either deferred or more cost-effectively addressed through demand-side measures or local generation, if there had been sufficient advance planning by VELCO and its owners. To avoid repeating this dilemma in a few short years, we have concluded that we should open a separate investigation into ways to ensure that cost-effective non-transmission alternatives are given full, fair, and *timely* consideration, and to determine methods for implementing (including funding) those non-transmission alternatives that bear lower societal costs than traditional transmission projects. In deciding to open this investigation, our

⁸⁰ Vermont PSB, Final Order, Docket 6860, 28 jan 2005, p. 5.

⁸¹ Ibid., p. 7.

fundamental goal is to make sure that VELCO does not come to us at the last minute (in terms of the horizon for transmission-system planning) for approval of a project that could have been deferred or displaced by more cost-effective alternatives.⁸²

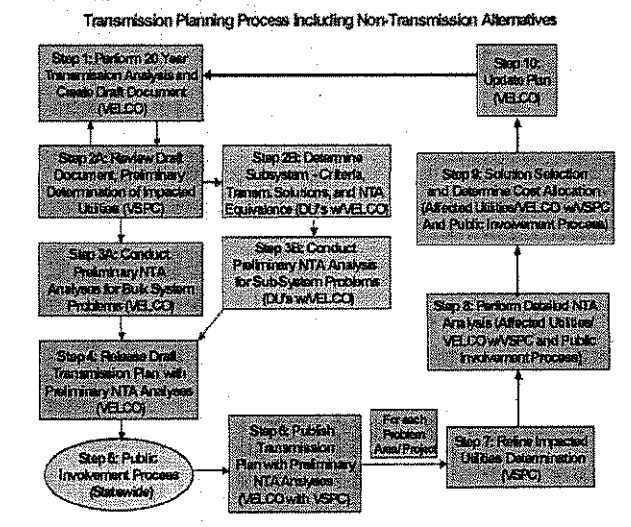
Cette enquête, devenu Docket 7081, s'est terminée en 2007, avec une entente négociée entre les parties et approuvée par le PSB. Cette entente crée, en vertu d'un *Memorandum of Understanding (MOU)* entériné par le PSB, un nouveau processus de planification du réseau de transport pour le Vermont, qui intègre la participation de VELCO, des services publics, des municipalités, du gouvernement, des représentants des différents secteurs de consommateurs, des groupes environnementaux et du public.

We conclude that the MOU significantly enhances the ability of the public to provide input into the selection of options to ensure adequate reliability of the electric system. As the Department notes in its brief, currently the public is solicited for comments on this issue only during the development of the electric distribution utilities' integrated resource plans or during public hearings in the Section 248 process, after the utilities have already selected a preferred option. The MOU provides for a planning process that is substantially more open, both in the greater dissemination of information to the public and in enhanced opportunity for the public to provide input during the planning process.⁸³

Ce nouveau processus de planification est résumé dans le prochain graphique:

⁸² Ibid., p. 11.

⁸³ Vermont PSB, Docket 7081, Final Order, 20 juin 2007, p. 29.



Ses détails de fonctionnement sont explicités dans le MOU.⁸⁴

Notons par ailleurs qu'après la décision finale du Docket 6860, la Législature du Vermont a adopté une loi obligeant VELCO, notamment, à préparer un plan de transport conjointement avec d'autres services publics, après la tenue des audiences publiques. La Loi précise que :

The objective of the plan shall be to identify the potential need for transmission system improvements as soon as possible, in order to allow sufficient time to plan and implement more cost-effective non-transmission alternatives to meet reliability needs, wherever feasible.⁸⁵

Il va de soi qu'aucune telle législation n'est pas en vigueur au Québec. Cela dit, rien n'empêche le Transporteur de s'inspirer des meilleurs pratiques dans nos régions avoisinantes dans l'élaboration de son processus de planification de transport.

⁸⁴ Vermont PSB, Docket 7081, Memorandum of Understanding, 2006.

⁸⁵ Vermont PSB, Docket 7081, Final Order, 20 juin 2007, p. 4.

9.8 Recommendations

Pour les raisons décrites ci-dessus, nous ne pouvons accepter les affirmations de M. Rose à l'effet que le système actuel de planification du réseau de transport répond aux exigences de la FERC.

Nous ne partageons pas non plus son opinion, ni celle de son client⁸⁶, à l'effet que la planification ne fait pas partie des exigences de réciprocité de la FERC. Citons à cet égard le paragraphe numéro 3 de l'Ord. 890 :

3. Second, the Final Rule will increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent, and coordinated transmission planning process. Transmission planning is a critical function under the pro forma OATT because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives. Despite this, the existing pro forma OATT provides limited guidance regarding how transmission customers are treated in the planning process and provides them very little information on how transmission plans are developed. These deficiencies are serious, given the substantial need for new infrastructure in this Nation. We act today to remedy these deficiencies by requiring transmission providers to open their transmission planning process to customers, coordinate with customers regarding future system plans, and share necessary planning information with customers.

À notre avis, un processus similaire à celui requis par la FERC ~~comporterait~~apporterait des bénéfices réels au régime de réglementation du service de transport au Québec, en permettant non seulement aux participants du marché non affiliés de participer pleinement dans la planification du réseau, mais aussi en permettant le Distributeur et les parties intéressées d'aider au Transporteur à identifier des solutions de moindre coût aux besoins liés à la croissance de la charge locale qui n'impliquent pas nécessairement l'ajout de nouveaux actifs de transport.

Nous recommandons donc à la Régie d'entreprendre un débat entre le Transporteur, ses clients et les autres parties intéressées sur la forme que devrait prendre un processus de planification ouvert et transparent, tel que l'exige la FERC pour les transporteurs sous sa compétencejuridiction.

⁸⁶ Voir la page 12, ci-dessus.

Par ailleurs, l'Attachment K de la British Columbia Transmission Corporation (BCTC) demeure un modèle extrêmement intéressant et pertinent pour un tel processus au Québec.

Soulignons ici que Powerex Corp. (la filiale commerciale de BC Hydro) a déjà écrit à la FERC pour expliquer les divergences entre autres de son Attachment K et le *pro forma*, où elle explique :

Although BCTC adopted the Commission's general transmission planning process, BCTC did not include the Commission's *pro forma* dispute resolution process in Attachment K of its OATT. Instead, BCTC explained that disputes in the transmission planning process will be addressed and resolved before the BCUC as part of the BCTC capital plan review process or in the BCUC's complaint process⁸⁷.

Il est à prévoir que HQ Energy Services (U.S.) Inc. produira éventuellement une lettre de la même nature, dans laquelle elle devra expliquer non pas les divergences entre l'Annexe K de TransÉnergie et le *pro forma*, mais l'absence totale de cet élément obligatoire de l'OATT.

La FERC a, bien entendu, beaucoup de discrétion, notamment dans ses décisions à l'égard de l'adéquation d'un OATT d'une affiliée étrangère. Son intérêt fondamental est de promouvoir la concurrence pour la desserte du marché américain. Toutefois, dans la mesure où les concurrents d'Hydro-Québec dans le marché américain considèrent que leur exclusion du processus de planification de TransÉnergie crée une discrimination induite en faveur des affiliées du Transporteur, on ne peut présumer que la FERC exercera nécessairement sa discrétion en faveur des affiliées.

Cela est d'autant plus vrai dans les circonstances où un concurrent d'Hydro-Québec qui désire utiliser le réseau de TransÉnergie pour livrer son énergie aux États-Unis, indique publiquement son mécontentement avec son traitement par cette dernière. Newfoundland Labrador Hydro (NLH) a fait des représentations devant la FERC à trois reprises depuis 2008, notamment pour lui faire part de ses plaintes, rejetées par la décision D-2010-053. Plus récemment, NLH a également déposé des commentaires à la FERC concernant le déroulement du présent dossier (joint aux présentes comme Annexe 6). Dans ce contexte litigieux, il serait surprenant si des divergences majeures entre les *Tarifs et conditions* et le *pro forma*, comme par exemple l'absence d'un Attachment K, ne ferait pas l'objet de contestations.

⁸⁷ Powerex, lettre du 20 novembre 2009.

Rappelons à cet égard l'affirmation de M. Rose à l'effet que c'était TransÉnergie qui l'aurait informé que l'Annexe K ne fait pas partie des exigences de réciprocité de la FERC. Il serait intéressant de savoir sur quel fondement cette affirmation a été faite. Découle-t-elle d'une analyse effectuée par le Transporteur lui-même ? Ou par ses affiliées?

Sans avoir vu les analyses en question, nous ne pouvons juger leur bien-fondé. Cela dit, il est surprenant qu'on ne se soit pas prononcé sur cette question avec certitude, puisqu'elle concerne un exercice futur de la discrétion qu'exercera un tribunal administratif, soit la FERC.

Si le maintien du *market-based rate authorization* de sa filiale HQ Energy Services (U.S.) Inc. est important pour Hydro-Québec, il serait à notre avis prudent que celle-ci encourage le Transporteur à ouvrir son processus de planification tel que précisé dans les Ordonnances, et à produire une Annexe K en bonne et due forme. Ce faisant, il servira non seulement à ses propres intérêts, mais aussi à l'intérêt public.

10 Appendice C

10.1 Les Ordonnances de la FERC

L'Appendice C-1 des *Tarifs et conditions* précise la méthodologie pour évaluer la capacité de transfert disponible. Connu en anglais sous le vocable *Available Transfer Capacity* (ATC), il s'agit d'un élément essentiel dans tout régime d'accès ouvert. Dans son Ordonnance 888, la FERC avait exigé que les transporteurs calculent et affichent leur ATC, tout en laissant chaque transporteur libre de choisir sa propre méthode de calcul⁸⁸. L'opportunité d'exiger, ou non, que l'ensemble des transporteurs sous la compétence de la FERC utilisent une seule et identique méthodologie a été un des thèmes majeurs du dossier menant aux Ord. 890 et al. Comme nous le préciserons dans les prochains paragraphes, la FERC a finalement décidé d'exiger une approche uniforme⁸⁹.

⁸⁸ Ord. 890, para. 62.

⁸⁹ Dans l'Ord. 890 (para. 208), la FERC refuse de fixer une méthodologie unique pour le calcul de l'ATC, optant plutôt de suivre l'approche de la NERC, qui offre un choix entre trois méthodologies (para. 210). En l'Ord. 890-C, elle indique que la décision finale se fera dans le dossier des normes de fiabilité de la NERC, qui a donné lieu éventuellement à l'Ord. 729 (24 nov 2009), qui adopte ces normes.

Aussi, si le maintien du *market-based rate authorization* de sa filiale HQ Energy Services (U.S.) Inc. est important pour Hydro-Québec, il serait à notre avis prudent que celle-ci encourage le Transporteur à ouvrir son processus de planification tel que précisé dans les Ordonnances, et à produire une Annexe K en bonne et due forme. Ce faisant, il servira non seulement à ses propres intérêts, mais aussi à l'intérêt public.

11.7 ATC

Pour des raisons expliquées ci-dessus, HQT aura à modifier éventuellement sa méthodologie de calcul de l'ATC pour se conformer aux normes de fiabilité de la NERC. Étant donné que ces normes sont déjà connues, il aurait été souhaitable qu'HQT les intègre dans ses *Tarifs et conditions* dès le présent dossier.

Par ailleurs, étant donné que l'utilisation de ces normes pour le calcul de l'ATC sera obligatoire à partir du 1^{er} avril 2010, et donc qu'elles seront obligatoirement intégrées dans les OATT des transporteurs américains, l'ajout de l'Appendice C-1 tel que proposé est essentiellement futile. Aucune raison n'a été avancée pour le promulguer autre que pour démontrer la conformité avec l'Ordonnance 890. Même si cet appendice aurait été en conformité avec l'Ord. 890 avant l'adoption de l'Ord. 729 — ce qui est douteux — elle ne le sera certainement plus après le 1^{er} janvier 2011.

N'étant qu'une harmonisation incomplète avec l'Ord. 890, au sans autre but, nous suggérons à la Régie de refuser l'ajout de l'Appendice C-1 proposé par HQT, et plutôt de lui demander de soumettre une nouvelle version qui sera en conformité avec les normes de fiabilité de la NERC et ce, le plutôt possible.