TAPPING THE POWER OF WIND:

FERC INITIATIVES TO FACILITATE TRANSMISSION OF WIND POWER

Darrell Blakeway & Carol Brotman White***

> So getting the [wind] plants built, getting the generation built is a very big step, but it's not the ultimate step. The ultimate step is getting that renewable power to the customer. . . . Barriers to entry for the wind energy have been and continue to be significant. . . . Because it's all about nondiscrimination. . . . It's giving a new technology which has a popular appeal, which has good environmental attributes, giving that technology a fair seat at the table with coal, nuclear, hydro, and gas. . . . I think the biggest barrier today that's preventing wide access to wind resources reaching customers is [the lack of] a robust transmission grid.[1]

I. INTRODUCTION AND SUMMARY

The wind energy industry is experiencing a phenomenal period of growth. It has become the fastest growing fuel-type for electrical generation installed in the U.S., with an average annual growth rate of over 27% from 2000–2004.[2] Its growth has been spurred by public sentiment, state and federal policies, economics, technological improvements, increasing utility acceptance, and evidence from other countries that integrating large amounts of wind-generated electricity into the system does not degrade system operations. In particular, this growth is motivated by a growing public concern about pollution from conventional fossil-fuel energy sources, about enhancing national energy security by decreasing dependence on imported fuel, and the possible adverse climate effects from accumulating carbon dioxide in our atmosphere. The growing commercial interest in wind energy, and other forms of renewables, has also been driven by dramatic increases in the prices of fossil fuels—crude oil, gasoline, natural gas, and coal—and thus electricity. These price increases, with little hope for future reductions, have made various renewable energy technologies economically competitive.

Once built, however, wind generation faces stiff obstacles in reaching

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1. Transcript of Technical Conference, *In re* Assessing the State of Wind Wholesale Electricity Markets at 6–8 (2004) (No. AD04-13-000) (quoting Pat Wood III, then Chairman of the FERC) [hereinafter Wind Wholesale].

2. This growth rate was from a small base of 2578 MW (megawatts) in 2000. Press Release, Am. Wind Energy Ass'n, Annual Rankings Demonstrate Continued Growth of Wind Energy Industry in the United States (May 12, 2005), *available at* http://www.awea.org/news/news050512sta.html. Wind energy represents 0.1% of total U.S. generation. The output of energy from wind generators is an even smaller percentage of total energy produced.

customers. Optimal wind resources are often located far from load, which may require additional transmission investment and construction. Wind developers and other generators might better utilize existing transmission paths by means of new transmission services that use transmission capacity during all but peak periods of transmission usage. Rules for financing and allocating costs of transmission facilities need to be re-examined in connection with developing wind resource areas. In response to these issues, the Federal Energy Regulatory Commission (FERC or Commission) has undertaken a series of steps to re-examine many of its rules to ensure they are not discriminatory against wind and other emerging renewable energy technologies.

First, the Commission conducted a rulemaking proceeding to establish special standards and procedures for interconnecting wind generation resources to the transmission system, because of their different characteristics compared to other conventional generation resources. After initiating the rulemaking proceeding, the Commission issued a Staff Briefing paper assessing the state of wind energy in the wholesale electricity markets, and conducted a public hearing on this topic. The Commission then convened a two-day public workshop to consider proposals for establishing new conditional firm and priority non-firm transmission services as a means of serving new wind developments because of insufficient additional firm transmission capacity. The Commission initiated a second rulemaking to establish non-punitive imbalance penalties for wind generators. Finally, the Commission acted on a filing to determine the mechanisms for recovery of the costs of transmission facilities needed to provide access to the grid for potential wind developments in the Tehachapi wind resource area of California.

A. *History of Recent Commission Actions Affecting Wind Energy*

Beginning in 2004, the FERC initiated a series of proceedings to address the problems faced by the wind industry, and particularly the problem of gaining access to the transmission system on reasonable and nondiscriminatory terms. The Commission had previously promulgated regulations governing interconnection of large generators to transmission. In Order No. 2003-A, on rehearing, the Commission noted that the standard interconnection procedures and agreement were based on the needs of traditional generators, and that a different approach might be necessary for generators relying on non-synchronous technologies, such as wind plants. The Commission appended a blank Appendix G as a placeholder for future adoption of special provisions for wind generation interconnection, as well as other asynchronous and/or intermittent energy sources.[3]

On September 24, 2004, the Commission conducted a technical conference on the American Wind Energy Association's (AWEA's) proposed standards for interconnection of wind generators to the grid, what AWEA labeled a "grid code." On January 24, 2005, the FERC issued a Notice of Proposed Rulemaking

3. Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, F.E.R.C. STATS & REGS. ¶ 31,146, 30,439, 68 Fed. Reg. 49,845 (2003) (to be codified at 18 C.F.R. § 35) [hereinafter Order No. 2003], *order on reh'g*, Order No. 2003-A, F.E.R.C. STATS. & REGS. ¶ 31,160, 31,018, 69 Fed. Reg. 15,932 (2004) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2003-A], *order on reh'g*, Order No. 2003-B, F.E.R.C. STATS. & REGS. ¶ 31,171, 70 Fed. Reg. 265 (2005) (to be codified 18 C.F.R. pt. 35) [hereinafter Order No. 2003-B).

(NOPR) on various provisions of AWEA's grid code,[4] and on May 25, 2005, issued the Final Rule as Order No. 661,[5] providing the content for Appendix G, with national standards for grid safety and reliability for wind generators. On July 5, the North America Electric Reliability Council (NERC) filed a Request for Rehearing. (Full discussion in Section II below.)

On November 22, 2004, the Commission issued the agenda for a technical conference on wind energy to be convened in Denver, Colorado, on December 1, 2004, along with a staff paper, *Assessing the State of Wind Energy in Wholesale Electricity Markets*, which laid out a number of the issues the Commission expected to address at the conference.[6] The issues raised by participants, audience members, and Commission staff gave rise to a number of initiatives discussed later in this article. (Full discussion in Section III, below.)

At the December conference, the Renewable Northwest Project (RNP)[7] and West Wind Wires (WWW)[8] announced that they had been working with Bonneville Power Administration (BPA or Bonneville) to develop a form of transmission service intermediate between long-term firm service and short-term non-firm. This new service would be called "Conditional Firm," and would be useful and available to intermittent wind and other generators that are unable to secure long-term firm transmission service. On February 1, 2005, the Commission issued a notice of a Technical Workshop on March 16–17, 2005, to discuss a draft of Bonneville's proposal, where the staffs of the BPA, FERC, and Western Electricity Coordinating Council (WECC) could work with market participants to develop definitions of conditional firm and other wholesale electric transmission services that could be offered in public utilities' open access transmission tariffs. (Full discussion in Section IV, below.)

Also at the December conference, a Southern California Edison Company (SCE) representative announced a proposal that SCE was working on to build long transmission lines to the Tehachapi wind resource area north of Los Angeles. He discussed the difficulty in expecting developers of relatively small wind projects to finance the costs of the extensive new transmission facilities there if such facilities were classified as "generation-tie facilities," needed only to connect generators to the grid. On March 24, 2005, SCE filed a request for declaratory order with the Commission, seeking rulings that the costs of three phases of its proposed transmission facilities from the Tehachapi Area could be rolled into system transmission costs that would be recovered from all

4. Notice of Proposed Rulemaking, *Interconnection for Wind Energy and Other Alternative Technologies*, F.E.R.C. STATS. & REGS. ¶ 61,036, 70 Fed. Reg. 4791 (2005) (Docket No. RM05-4-000). Filings in any FERC proceeding, and Commission orders and notices referred to in this article, may be found on the FERC website's eLibrary: www.ferc.gov/docs-filing/elibrary.asp. Search by docket number for all filings in a proceeding, or by docket number and date for any Commission notice or order.

5. Order No. 661, *Interconnection for Wind Energy*, F.E.R.C. STATS. & REGS. ¶ 31,186, 70 Fed. Reg. 34,993 (2005) (to be codified at 18 C.F.R. pt. 35), *reh'g pending* [hereinafter Order No. 661].

6. FED. ENERGY REGULATORY COMM'N, ASSESSING THE STATE OF WIND ENERGY IN WHOLE ELECTRICITY MARKETS, Docket No. AD04-13-000 (Nov. 2004), *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/11-04-wind-report.pdf [hereinafter WIND ENERGY]; *See* Wind Wholesale, *supra* note 1.

7. Renewable Northwest Project (RNP) is a Portland, Oregon-based non-profit renewable energy advocacy organization.

8. West Wind Wires (WWW) is a wind advocacy program under the auspices of Western Resource Advocates, which represents wind in transmission planning and operational forums throughout the Western Electricity Coordinating Council (WECC) region.

transmission customers served by the California Independent System Operator (CAISO).[9] On July 1, 2005, the Commission issued an order granting SCE's request in part, but denying rolled-in rate treatment for the segment of new transmission lines closest to the anticipated new wind projects. (Full discussion in Section VII, below.)

On April 14, 2005, the Commission issued a Notice of Proposed Rulemaking on Imbalance Penalties[10] to require public utilities to append an intermittent generator imbalance service schedule to their Open Access Transmission Tariffs (OATTs).[11] The schedule would widen the service to reflect a bandwidth of +/- 10% and allow net hourly intermittent generator imbalances within the bandwidth to be settled at a system's incremental cost at the time of the imbalance. The Commission also reiterated its policies that transmission customers are and must be allowed to change their schedule up to twenty minutes before the hour. (Full discussion in Section V, below.)

On April 22, 2005, the Commission conducted a Technical Conference "to examine impediments to investment in electric transmission infrastructure and explore potential solutions—including the formation of new business models as well as appropriate ratemaking incentives that would encourage new investment in transmission."[12] The conference was convened more than two years after issuance of a Notice of Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid.[13]

On May 12, 2005, the Commission issued the Final Rule on Standardization of Small Generator Interconnection Agreements and Procedures (Order No. 2006) for generators of no more than 20 MW capacity and concluded that no special provisions, such as those in the proposed Grid Code for interconnection of large generators, were necessary for small wind generators.[14] (Full discussion in Section VI, below.)

B. Other Actions That Would Facilitate Development of Wind Energy

After having taken a number of steps to ensure that interconnection rules and transmission tariff provisions are fair and non-discriminatory to wind development, and that existing transmission capacity is being used most efficiently, the next important thing that can be done to facilitate greater use of wind energy is to implement policies that will foster construction of new

9. *S. Cal. Edison Co.*, 112 F.E.R.C. ¶ 61,014, 61,137 (2005).

10. Notice of Proposed Rulemaking, *Imbalance Provisions for Intermitted Resources*, F.E.R.C. STATS. & REGS. ¶ 61,026, 70 Fed. Reg. 21,349 (2005) [hereinafter *Imbalance Provisions*].

11. Imbalances are of two types: generation and energy. Generation imbalances occur when the scheduled output is different from (out of balance with) the energy delivered; energy imbalances occur when the energy requested by consumers (load) is out of balance from what is needed (demand) in real time. Energy imbalance service is provided by the system operator to rectify the differences as an ancillary service under Order 2003.

12. FED. ENERGY REGULATORY COMM'N, TRANSMISSION INDEPENDENCE AND INVESTMENT, TECHNICAL CONFERENCE AND AGENDA, Docket No. AD05-5-000 (Apr. 14, 2005).

13. *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 F.E.R.C. ¶ 61,032 (2003); FED. ENERGY REGULATORY COMM'N, PROPOSED PRICING POLICY FOR EFFICIENT OPERATION AND EXPANSION OF TRANSMISSION GRID, DOCKET NO. PL03-1-000 (Jan. 15, 2003).

14. Order No. 2006, *Standardization of Small Generator Interconnection Agreements and Procedures*, F.E.R.C. STATS. & REGS. 31,180, 70 Fed. Reg. 34,189 (2005) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2006].

transmission facilities. There will be many beneficiaries of new transmission infrastructure—all forms of generation, whether renewable or not, increased competition among generation sources, and increased reliability of the transmission system. But transmission facilities in locations where they can be economically accessed by wind generators in wind resource areas are critical to tapping the power of wind.

The costs of transmission facilities for wind developments are often higher than for conventional energy plants that can locate nearer electric transmission facilities and system loads. Moreover, the load factors for use of such transmission facilities by wind generators are lower than for generators that can be run almost continuously, or when most needed.[15] Wind resources must be tapped where and when they are available, and many land-based wind resources are in areas remote from the major population centers, and thus the load centers.[16] This is especially true for many mid-continent wind resource areas. On the other hand, there are strong wind resource areas just offshore of the United States, including many sites on the East Coast that are in relatively shallow waters, where the costs and technological feasibility of offshore wind developments are the best.[17] Moreover, many of the country's population centers are closer to the offshore wind resources than the mid-continent resources, and can thus be interconnected to the grid with lower cost transmission facilities, although overall costs of offshore developments are still higher than onshore developments.

The outcome of public debates over the propriety and suitability of siting offshore wind developments between Cape Cod and Nantucket Island (the Cape Wind Project) and southeast of Jones Beach off Long Island (Long Island Offshore Wind Park) will have significant effects on the prospects for further offshore wind developments. The FERC could examine its pertinent jurisdiction to develop any applicable policies enabling fair interconnection of transmission infrastructure necessary to allow offshore developments.

Integrating and efficiently utilizing wind power is much easier in regions

15. A generator's or transmission line's load factor (or capacity factor) is a ratio expressed as a percentage of the average of the facility's capacity used over some period of time compared to 100% usage at all times during that period. Thus, a wind generator that generates at 100% of its capacity 35% of the time, and sits idle the other 65% of the time would have a 35% load factor. A transmission line that is fully utilized 50% of the time, and half utilized the other 50% of the time would have a load factor of 75%. State of the art wind generators in prime wind resource areas typically generate some electricity about 85% of the time, and have a load factor of about 35%.

16. A load center is the area where the electric power is being used, e.g., urban and/or industrial regions.

17. "NREL studies indicate more than 50,000 MW of shallow offshore resources (<30-m) are available near coastal load centers, and the resource in deeper waters is 10 to 20 times larger," although it is clear that offshore technology is not as advanced and is currently more expensive than onshore wind technology. *Offshore Energy: Hearing Before S. Comm. on Natural Resources and Energy*, 109th Cong. (Apr. 19, 2005) (statement of Dr. Robert W. Thresher, Director, National Wind Technology Center, National Renewable Energy Laboratory (NREL)), *available at* http://energy.senate.gov/hearings/testimony.cfm?id=1463&wit_id=4184. The National Wind Technology Center website has wind resource maps, *available at* http://www.nrel.gov/wind/wind_map.html (last modified Aug. 2005). *See also* W. MUSIAL, S. BUTTERFIELD, NATIONAL RENEWABLE ENERGY LABORATORY, FUTURE FOR OFFSHORE WIND ENERGY IN THE UNITED STATES (2004), *available at* http://www.nrel.gov/docs/fy04osti/36313.pdf. *See also* MASSACHUSETTS TECHNOLOGY COLLABORATIVE, U.S. DEPARTMENT OF ENERGY, & GE, A FRAMEWORK FOR OFFSHORE WIND ENERGY DEVELOPMENT IN THE UNITED STATES (2005) (concluding there is potential for more than 900,000 MW of wind generation within 50 miles of United States coasts), *available at* http://www.masstech.org/offshore/final_09_20.pdf.

with independent system operators (ISOs) or regional transmission organizations (RTOs), with their large control areas, centrally dispatched energy markets, and day-ahead and real-time spot markets.[18] The most efficient and cost-effective use of wind power, due to its intermittent nature, is to operate all other generators within a fairly large geographic area to augment the power from wind.[19] In ISOs and RTOs, the market and operating rules and centrally dispatched balancing markets tend to be wind-friendly by their very nature. Even where no ISOs exist, the larger the "control area" for coordinating power markets, the easier it is to integrate wind resources and to dispatch the system efficiently. In parts of the country that do not have ISOs or RTOs, the Commission could continue to develop provisions of its electric utility Open Access Transmission Tariffs (OATTs) that eliminate undue discrimination against wind resources.

The proposals for conditional firm and high-priority non-firm transmission service will be evaluated when they are formally proposed to assure that existing transmission capacity is fully and efficiently utilized. Careful attention will also be given to how transmission owners calculate their Available Transfer Capability (ATC) (also called Available Transmission Capacity) to assure that transmission capacity is not only being used efficiently, but also fairly.[20] Conditional firm and other alternative transmission products are not a substitute for construction of new transmission facilities, but can serve to utilize existing transmission facilities more fully and efficiently until they can be augmented.

The most important impediment for development of many of our wind resources is the lack of a robust transmission system, as former Chairman Pat Wood III has often noted. Accordingly, the Commission's efforts to foster and implement policies that remove barriers to the expansion of the transmission grid and provide appropriate incentives for private and public investment in such expansion, will be most important to the long-run interests for all forms of generation, including wind, and the enhanced reliability and security of our national electric systems.[21]

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18. Most ISOs and RTOs not only manage the transmission system, but also purchase enough electric energy for the next day, or next hour, to precisely balance the demand and supply. Other customers beside the system operators also purchase in this "spot market" for electric energy. California's CA-ISO does not have a day-ahead market, but does have a model program to incorporate intermittent resources fairly (see below, in section V. B.).

19. The variable costs of operating wind generators are lower than nearly all other sources of energy because the wind is free; so it makes sense to use the wind energy first and then draw on energy from other types of generators to meet the total demands of the system's customers.

20. On May 27, 2005, the Commission issued a Notice of Inquiry (NOI) requesting comments on the advisability and feasibility of revising and standardizing available transfer capability calculations, and the most expeditious way to obtain an industry wide standard for such calculations. Notice of Inquiry, *Information Requirements for Available Transfer Capability*, F.E.R.C. STATS. & REGS. ¶ 61,274 (2005), 70 Fed. Reg. 34,417 (2005).

21. Twenty-five years ago, R. Buckminster Fuller articulated his vision of a world-wide transmission grid interconnected to millions of wind generators around the world. With high-voltage transmission lines connecting all the continents, including lines across the Bering Strait from Alaska to Siberia, wind energy could become the base load resource because of its lack of any fuel costs. The most economic operating procedure would be to dispatch other forms of generation to meet the demand that wind resources alone cannot serve. With the numbers of generators Fuller was envisioning, the intermittent character of wind generation becomes less of a problem, because the wind blowing in some regions would compensate for generators becalmed in other regions. The system could always use the most economical generators (wind or otherwise) dispersed over the globe to serve the diversity of peak loads occurring in different transmission-interconnected time zones. R.

II. INTERCONNECTION FOR WIND ENERGY

Order No. 2003, the Large Generator Interconnection Rulemaking, was issued after nearly two years of stakeholder input involving generators, transmission providers, regulators, and trade associations. It required jurisdictional public utilities to amend their OATTs to include standard interconnection procedures (LGIP) and agreements (LGIA) for generators larger than 20 MW. Subsequently, in Order No. 2003-A, the Commission recognized that the interconnection needs of non-synchronous generators,[22] such as wind plants, may be different than those of large synchronous generators, and that some provisions of the LGIA and LGIP may not be appropriate. Order 2003-A thus appended a blank Appendix G to the standard LGIA as a placeholder for future adoption of requirements for newer technologies.[23] In 2004, AWEA initiated a series of events which led to the Commission's approving requirements for wind generators in Appendix G.

A. *Timeline for Grid-Interconnection Rule for Large Wind Power Facilities*

On May 20, 2004, AWEA requested that the FERC hold a Technical Conference to address the blank Appendix G.[24] AWEA voluntarily proposed national wind performance and equipment standards that would address the concerns of both grid operators and the wind generation industry. The equipment, or technical, standards included low-voltage ride-through (LVRT) capability, power factor design criteria (reactive power), and supervisory control and data acquisition (SCADA) capability.[25] The process standards included wind plant interconnection modeling, self-study of interconnection feasibility, and queuing procedures.[26]

On September 24, 2004, the FERC staff held a Technical Conference on the interconnection of wind energy projects and other alternative technologies. Sixteen panelists addressed staff questions on the special interconnection requirements for wind energy, the engineering implications of provisions in the proposal, and the potential impact on grid reliability and safety if the proposed standards for wind generators were to be adopted. Staff also asked panelists

BUCKMINSTER FULLER, CRITICAL PATH (St. Martin's Press, 1981); *see also* GLOBAL ENERGY NETWORK INSTITUTE, GLOBAL ENERGY GRID—THE DETAILS, *available at* http://www.geni.org/globalenergy/issues/overview/grid.shtml (last visited Sept. 28, 2005).

22. "A wind generator is considered non-synchronous because it does not run at the same speed as a traditional generator. A non-synchronous generator possesses significantly different characteristics and responds differently to network disturbances." Order No. 661, *supra* note 5, at 31,581 n.4.

23. Order No. 2003-A, *supra* note 3, at 31,019.

24. *Id.* AWEA is a national trade organization representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind energy resources in the U.S. AWEA members include wind turbine manufacturers, component suppliers, project developers, project owners and operators, financiers, researchers, renewable energy supporters, utilities, marketers, customers, and their advocates. FED. ENERGY REGULATORY COMM'N, PETITION FOR RULEMAKING, OR, IN THE ALTERNATIVE, REQUEST FOR CLARIFICATION OF ORDER NO. 2003-A, AND REQUEST FOR TECHNICAL CONFERENCE OF THE AMERICAN WIND ENERGY ASSOCIATION, Docket No. RM02-1-005 [hereinafter AWEA Petition for Rulemaking].

25. Writing about electricity is challenging, because it has a number of characteristics that can be described and quantified, but which are not easily explained or visualized. Legal practitioners with non-technical educations writing about electrical characteristics quantified as voltage, amps, vars, and reactive power must rely on reviews by technical experts to avoid errors.

26. AWEA Petition for Rulemaking, *supra* note 24, at 2–4.

whether the proposed grid standards were applicable to small wind generation.[27]

On January 19, 2005, the FERC issued a proposed Rule for Wind Power Interconnection. The NOPR recognized the differences between connecting wind plants and conventional large central generation, and proposed performance and process standards for large wind generation in response to the areas suggested by AWEA. In its request for comments, the FERC asked whether other technologies should also comply with these standards.

The Final Rule on Interconnection for Wind Energy was issued on June 2, 2005, and published in the Federal Register on June 16 as Appendix G to Order No. 2003.[28] The Rule applies only to the interconnection of wind plants over 20 MW. All public utilities subject to Commission jurisdiction are required to append the standard procedures and technical requirements for the interconnection of large wind generators to their standard large generator interconnection procedures (LGIP) and agreements (LGIA) in their OATTs.[29]

On July 5, the NERC requested a rehearing of Order No. 661, asserting that the adopted low-voltage ride-through (LVRT) standard for wind would permit violations of a reliability rule.[30] On August 5, the FERC accepted a joint request from AWEA and NERC to extend the effective date of the Final Rule for 60 days, to allow them time to negotiate a solution. On September 19, AWEA and NERC jointly filed a report suggesting phased-in changes to the LVRT standard. Comments were due to the FERC by October 3; the Commission had not ruled on their proposed solution at the time of publication.

B. *Why Did Wind Energy Need Separate Standards?*

AWEA's proposal recognized the maturing of wind energy technology, its increasing presence on several transmission systems, and the needs of wind generators to be responsible grid citizens in terms of grid reliability and safety.

The performance and process standards, which became known as the "grid code," would provide national interconnection standards for wind developers and manufacturers, rather than the existing patchwork of standards, which vary by region, and for different manufacturers and technologies.[31] Similar standards have been adopted in other countries once the wind industry reached similar levels of technological maturity and rates of penetration on transmission systems.

Wind power requires separate interconnection rules because large wind plants can consist of hundreds of small non-synchronous induction generators, located on sites laid out over a number of miles, and connected to the transmission system at a single point through a medium voltage collector system.[32] Historically, wind generation has consumed reactive power, rather than providing it to the grid, as do large synchronous generators. In some cases, facilities are needed to provide reactive power to offset the effect of wind

27. Transcript of Technical Conference, *In re* Interconnection for Wind Energy and Other Alternative Technologies (2004) (No. PL04-15-000).

28. Order No. 661, *supra* note 5 (adopting Appendix G to Order No. 2003).

29. Order No. 661, *supra* note 5.

30. Standard TPL-002-0, System Performance Following Loss of a Single BES (Bulk Electricity Element).

31. *Id.* at 31,591.

32. Order No. 661, *supra* note 5, at 31,599, 31,601.

generators.[33]

In its Rule, the FERC noted that standards "minimize [the] opportunities for undue discrimination by Transmission Providers and remove[s] unnecessary obstacles to the development of wind generation . . . ."[34] The changes between the NOPR and Rule reduce the burdens on wind plant to install costly equipment that is not needed for safety or reliability. A national standard can benefit consumers; and a stable, consistent design target decreases manufacturing costs, thus lowering wind power's cost. A standard encourages competition, increases efficiency, and promotes technological improvement.

C. *What Standards Are Included and Under What Circumstances?*

1. Equipment or Technical Standards

AWEA's proposal and the Final Rule address equipment standards for wind interconnection to enhance system reliability in three areas: the ability to stay online during voltage disturbances, to provide reactive power to the grid, and to have real-time communications and data exchange capability between the wind plant and grid operator.

Low-voltage ride-through (LVRT) equipment enables wind plants to stay on-line during voltage disturbances on the grid. Early wind generation technology often was shut down when the grid system experienced sudden drops in voltage. Unlike large synchronous facilities, wind generators are not equipped with automatic voltage controls. Wind generators want to stay on-line, and technology advances have made it possible. AWEA proposed a low-voltage ride-through standard for large wind plants. The Rule adopts the LVRT standard, but changed the language to allow interconnection of wind plants that possess LVRT capability, where it is needed, without requiring them to provide that capability in every situation. It also notes that the standard is similar to those used in other countries and recently adopted by the Western Electricity Coordinating Council (WECC).[35] AWEA and NERC proposed an interim standard for wind farms with interconnection agreements signed in 2006 or which had turbine orders executed in 2005. It would require wind farms to stay on line during system voltage sags as low as 15% of normal, for up to 0.15 seconds. For wind farms developed after these dates, the standard would require them to stay connected through voltage dips to as low as zero volts.

Reactive power support for the grid, also known as "power factor design criteria," is necessary to balance the reactive power needs of the transmission system. Because of the increasing size of wind plants and their increasing presence on various transmission systems, AWEA proposed that wind facilities should demonstrate this capability. The rule adopts the same criteria for large wind power as for large conventional generation, which requires that plants operate within a power factor range of 0.95 leading to 0.95 lagging, where needed. In addition, the Rule gives wind plants the flexibility to use a variety of

33. Reactive power is a measure of the back and forth flows of instantaneous power between electric and magnetic fields.

34. Order No. 661, *supra* note 5, at 31,583.

35. *Id.* at 31,589.

combinations of equipment to provide reactive power capability,[36] including dynamic voltage-ampere reactive[37] (DVAR) banks, switched capacitors (static), or a combination.[38]

SCADA capability enables real-time communications and data exchange between the power producers and grid operators. It consists of bi-directional electronic communications equipment, which allows the exchange of information for scheduling and forecasting. The Rule requires that the wind interconnection customer provide SCADA capability, with the underscored caveat that the specific capability and type of information to be exchanged must be negotiated between the wind plant and the transmission provider, outside of Appendix G and the LGIA. The Rule does not give the transmission provider the right to control the wind plant.[39]

2. Process Standards

AWEA's proposal and the Final Rule address two process standards for wind interconnection: models for wind plant interconnection and a change in procedures to enter the interconnection queue.

AWEA's "grid code" urged the Commission to require Transmission Providers and wind generator manufacturers to "participate in a formal process for developing, updating and improving the engineering models and turbine specifications used for modeling the wind plant interconnection."[40] In both the proposed and final Rule, the FERC recognized that wind interconnection modeling improvements would be helpful, but suggested that this process should be undertaken by industry technical groups, the NERC, and regional reliability councils.[41]

The second process proposal addressed what the wind industry saw as a "Catch-22" in entering the interconnection queue. It suggested that wind plants be allowed to enter the queue and receive the base-case data to "self-study" the feasibility of its proposed interconnection without having first submitted a formal "interconnection request" that includes power and load flow data and fully completed plant electric design specifications, as required under Order No. 2003. AWEA argued that turbine selection and the electrical design of the entire wind farm is an output of the feasibility study, which could only be determined once the base case data was received, especially since the turbine selection decision is influenced by grid conditions at the point of interconnection (POI).[42]

In the NOPR, the FERC denied AWEA's request, in part, not to favor one form of generation over another, and in part not to compromise Critical Energy Infrastructure Information. In the Rule, the FERC found a compromise on

36. Order No. 661, *supra* note 5, at 31,594.

37. VAR is voltage-ampere reactive, and is a measure of reactive power, the way that MW is a measure of the energy ("real power") produced by a plant. Reactive power is a measure of the back and forth flows of instantaneous power between electric and magnetic fields. The important notion here is that generated reactive power and consumed reactive power need to be balanced on the transmission system in the tight range set forth in order for system stability.

38. AWEA Petition for Rulemaking, *supra* note 24.

39. Order No. 661, *supra* note 5, at 31,596–31,597.

40. AWEA Petition for Rulemaking, *supra* note 24, at 12.

41. Order No. 661, *supra* note 5, at 31,597.

42. AWEA Petition for Rulemaking, *supra* note 24, at 13–14.

entering the queue. The Rule allows a wind plant to provide a preliminary set of design specifications that depict the entire wind plant as a single equivalent generator in terms of its megawatt output (MW or real power) and reactive power (M-VAR) range. The wind plant developer would then pay a fee, enter the queue, and receive the base case data as provided in Order No. 2003.[43]

The Order noted that some of the data received by the wind plant from the transmission provider was key to final siting:

> [the] physical placement of the turbines, transformers and voltage support devices that affect the electrical characteristics created by the medium voltage collector system depend on the size and location of the wind plant and the location of other generators on the Transmission Provider's system. For these reasons, wind plant developers are unable to submit completed design specifications for individual wind turbines until much later in the interconnection process, in comparison with other developers.[44]

D. *Where Should Technical Capability Be Measured?*

The LVRT modification proposes that it be measured at the "high-side" of the step-up transformer, that is, on the transmission side of the system. While the NOPR proposed that LVRT and power factor capability be measured at the high voltage side of the wind plant substation transformer,[45] the Rule clarifies that the appropriate point to measure the capability is the Point of Interconnection (POI). The Rule notes for LVRT that the "Point of Interconnection is the point at which the Interconnection Customer's responsibility ends and the Transmission Provider's responsibility begins."[46] The POI is also appropriate for measurement of the power factor, because it is closer to the bulk electric power system, and this requirement is consistent with Order No. 2003. One commenter who concurred noted that while the POI may be more costly for wind plants with long generation tie lines, using a different measuring point would not meet system reliability needs.[47]

E. *When Should the Standards Be Required and Be Effective?*

The Rule makes a critical departure from the NOPR by requiring LVRT and reactive power standards only when needed by the grid for safety or reliability. The Rule shifts the burden of proof from wind plants to transmission providers to demonstrate the need for additional equipment at a particular location. The NOPR would have required large wind plants seeking interconnection to "demonstrate LVRT capability" and to "maintain a power factor within the range of 0.95 leading to 0.95 lagging" (as required by Order No. 2003) "unless waived by the Transmission Provider on a comparable and not unduly discriminatory basis for all wind plants."[48]

The Rule, instead, adopts "the standard[s] proposed in the NOPR, but will not require that [they] be met unless . . . the Transmission Provider shows, through the System Impact Study, that such capability is required [of that plant]

43. Order No. 661, *supra* note 5, at 31,599.

44. *Id.*

45. Order No. 661, *supra* note 5, at 31,584, 31,592.

46. *Id.* at 31,588.

47. Order No. 661, *supra* note 5, at 31,587, 31,592–31,593.

48. *Id.* at 31,584, 31,589.

to ensure safety or reliability."[49] Numerous commenters to the NOPR waiver provision expressed concern that the transmission provider would routinely require the new equipment standards of all wind plants, whether needed or not. A universal requirement would add unnecessary costs without necessarily increasing reliability, thus inhibiting wind power development. As Chairman Wood said, in effect, at the May 25, 2005 Commission meeting, just because a transmission operator wants something, does not mean it is necessary for reliability or for engineering requirements, and the Commission needs to prevent undue discrimination.[50]

The Rule creates two compliance dates. The procedural requirements take effect sixty days from publication in the Federal Register, but create a transition period for the substantive technical requirements for LVRT, SCADA, and power factor design criteria. These will be applied, if applicable, only to LGIAs signed or filed with the Commission on or after January 1, 2006, or six months from the date of the Rule's publication in the Federal Register, whichever is later.[51] This transition period allows manufacturers sufficient lead-time to add the equipment features to wind turbines. A transition would not disrupt deliveries of turbines already ordered before the Rule was issued. Existing LGIAs are grandfathered. Transmission providers are required to amend their LGIAs and LGIPs with these procedures and technical requirements, as provided in Appendix G.[52]

The Rule imposes a six-month time limit between a wind plant's receiving base case data from the transmission provider and its submitting completed detailed design specifications. The transmission provider needs these details to complete its System Impact Study. The deadline ensures that the transmission provider doesn't have "uncertain projects in the queue."[53]

III. Assessing the State of Wind Energy in Wholesale Electricity Markets

On November 22, 2004, the FERC issued a Staff Briefing paper that described the current state of wind power, the drivers behind its growth, and the issues wind energy faces for future development. Concurrently with issuing the Staff Paper, the FERC issued an agenda for a technical conference to discuss issues raised in that paper and a series of specific questions addressed to the invited panelists.[54]

49. Order No. 661, *supra* note 5, at 31,587.

50. FED. ENERGY REGULATORY COMM'N, COMMISSION MEETING, Item E-1 (May 25, 2005); Order No. 661, *supra* note 5.

51. Order No. 661, *supra* note 5, at 31,602.

52. *See* Order No. 661, *supra* note 5.

> "In the NOPR, the Commission proposed to include Appendix G as an attachment to the LGIA only. Upon further consideration, the Commission directs that the Final Rule Appendix G provisions related to completion of the Interconnection Request by a wind plant interconnection customer be appended to the LGIP, since they are procedural in nature, and that the remaining technical requirements be appended to the LGIA, to ensure that the provisions adopted here are applied throughout the interconnection process."

Id. at 31,583 n.14.

53. Order No. 661, *supra* note 5, at 31,600.

54. WIND ENERGY, *supra* note 6.

A. *Staff Briefing Paper*

The briefing paper described a number of drivers and issues affecting the development of wind power, some of which are described below, others are noted in the introduction and throughout this article where relevant to particular actions undertaken by the FERC.

1. State Policies

States' policies increasingly promote renewable energy through a variety of mechanisms. Twenty-one states and the District of Columbia have enacted or administratively promulgated Renewable Portfolio Standards (RPS); nine of these were passed or amended in 2004 and seven were passed or amended in 2005.[55] An RPS reflects a State's commitment to adding renewables to the mix of generation, generally at a rate that increases yearly and which applies to all retail electricity suppliers. The durations of an RPS, the percent of renewables in the goal, and which fuels are included vary widely. Some States that have already achieved their initial goals are considering raising them by amending their RPS. A few have specified a percent of the total that must be met by a particular fuel, such as wind or solar. States have enacted these standards to encourage fuel diversity, to lessen dependence on fuel imports, to acknowledge public environmental concerns, and to meet more stringent EPA emissions requirements.

Other state renewable incentives include loan funds, grant programs, tax exemptions, net metering, and green power purchasing programs. Many state governments have committed to purchasing an increasing percent of their supply from renewable energy. Some states without an RPS are also encouraging retail electric suppliers to increase the percent of renewables in their generation mix or requiring some larger suppliers to include renewable energy as a tradeoff for other generation approvals.

2. Costs More Attractive

A modern wind turbine can generate electricity for 4¢–6¢/kWh, before federal tax subsidies or other state financial incentives.[56] After subsidies, large-scale wind in the United States today can sell power to utilities at a low of 2¢/kWh, and a high of around 5¢/kWh, with a more common range of 2.5¢/kWh–3.5¢/kWh for new projects.[57] Given current natural gas prices, the levelized cost of building a new wind generation plant can compare favorably with the cost of a new gas-fired plant, which costs at least 5.5¢/kWh, including

55. *Id.* An RPS imposes an obligation on load serving entities to provide a stated quantity or percentage of their electric energy from renewable or alternative energy sources by some target date. Forms of RPS requirements vary considerably from state to state. In Pennsylvania, the portfolio standard included waste coal and integrated combined coal gasification technology, as well as large scale hydroelectric projects (often excluded from qualifying renewable energy categories), and distributed energy facilities that use fossil fuels. Many states, however, allow existing renewable resources to count towards their goals, which provide less incentive to build new renewable generation.

56. This estimate was made in late 2004 and early 2005, before global steel prices rose. Because it takes 60 tons of steel to make a modern 1MW+ turbine, AWEA estimated in early summer 2005 that pre-subsidy prices were between 5.5¢ and 9.5¢/kWh.

57. E-mail from Ryan Wiser, Lawrence Berkeley National Laboratory (LBNL), to Carol Brotman White (Nov. 2004) (on file with author) [hereinafter Ryan Wiser E-mail].

both fuel and capital costs.[58]

3. Companies' Increased Comfort With Wind Power

Large international companies are making changes in their energy purchases to begin compliance with global carbon caps, while others include assumptions on carbon costs in their energy analyses, on the assumption that the United States may some day institute carbon taxes, caps, or adders. The California Energy Commission has already instituted a carbon adder that utilities must use when they compare the costs of responses to RFPs (requests for proposals) for future capacity. Some utility planners are voluntarily calculating similar adders when they assess new resources. These economic assumptions give an additional boost to wind resources as a part of companies' energy portfolios, many of which are seeking hedges against rising fuel prices.

As utilities become more familiar with integrating wind resources into their portfolios and transmission systems, they are less wary about dealing with issues such as the intermittency of wind. They have discovered that these issues can be resolved without large additional expenditures. Recent studies for Minnesota and New York demonstrated that the addition of large amounts of wind on their systems could be accomplished at an incremental operating cost between \$1/MWh and \$4.60/MWh, with similar reductions in market prices.[59]

4. Production Tax Credits

The Federal Production Tax Credit (PTC) for wind-generated electricity was renewed in October 2004; the PTC, now 1.9¢/kWh,[60] is good for ten years from the date a project is operational for projects online by the end of 2005. Its renewal set off a flurry of new wind generation projects. Within a month, five utilities and their affiliates announced that fully permitted projects totaling 829 MW, all stalled during the lapse, were going forward. The wind industry association expected between 2,000 MW and 2,500 MW to be installed in 2005.[61]

The PTC is a key for financing wind projects, because it increases annual cash flow by close to 38% for the first ten years of a plant's life.[62] The PTC's

58. MARK BOLINGER, RYAN WISER & GARRETT FITZGERALD, THE IMPACT OF STATE CLEAN ENERGY FUND SUPPORT FOR UTILITY-SCALE RENEWABLE ENERGY PROJECTS (Oct. 2004), *available at* http://eetd.lbl.gov/ea/ems/cases/LBNL-56422.pdf; Ryan Wiser E-mail, *supra* note 57 (basing his analysis on data from the Energy Information Administration's (EIA) Assumptions to the Annual Energy Outlook 2005, ENERGY INFORMATION ADMINISTRATION, ANNUAL ENERGY OUTLOOK 2005 (2005), *available at* http://www.eia.doe.gov/oiaf/aeo/assumption, and NYMEX closing gas prices, April 1, 2005).

59. ENERNEX CORP., XCEL ENERGY AND THE MINNESOTA DEPARTMENT OF COMMERCE, WIND INTEGRATION STUDY—FINAL REPORT (Sept. 2004), *available at* http://www.enernex.com; GE ENERGY, THE EFFECTS OF INTEGRATING WIND POWER ON TRANSMISSION SYSTEM PLANNING, RELIABILITY, AND OPERATIONS, REPORT ON PHASE 2: SYSTEM PERFORMANCE EVALUATION (Mar. 2005), *available at* http://www.nyserda.org/publications/wind_integration_report.pdf.

60. 26 U.S.C. § 45 (2000); Working Families Tax Relief Act of 2004, Pub. L. No. 108-311, 118 Stat. 1166 (2004). The PTC for wind projects was created in 1992 by the Energy Policy Act at 1.5¢/kWh, to be adjusted for inflation. The IRS adjusted the PTC for inflation to 1.9¢/kWh for all projects placed into operation in 2005. *See* 70 Fed. Reg. 18,071 (2005).

61. Press Release, Am. Wind Energy Ass'n, U.S. Wind Industry Continues Expansion of Clean, Domestic Energy Source (Jan. 27, 2005), *available at* http://www.awea.org/newsroom/index.html.

62. STANDARD & POOR'S, RATINGS DIRECT, PRESALE: FPL ENERGY NATIONAL WIND LLC 2 (Feb. 10, 2005).

history has been one of two-year extensions followed by a lapse of several months before its renewal, creating a boom-bust cycle in the building of wind projects.[63] This cycle creates planning uncertainty for wind developers, financial backers, turbine manufacturers, and skilled workers.[64] While several groups called upon Congress to extend the PTC for five years; the final Energy Bill passed by the 109th Congress extended it for two years, through 2007.[65]

5. Long-Term Contracts

Another key to wind development is the availability of long-term contracts for the off-take of wind power, usually for ten to twenty years. Unlike in the early years of wind power development under provisions of the Public Utilities Regulatory Policy Act of 1978 (PURPA),[66] modern wind plants tend to be built either as merchant plants or in response to a utility RFP (request for proposal) for wind. In both cases, developers need to secure long-term power purchase agreements to obtain financial backing. Some states encourage long-term contracts in their RPSs; in others where utilities are moving slowly to meet their mandates, wind advocates are encouraging states to require long-term contracts to enable renewable financing.[67]

B. Technical Conference on Wind Energy in Wholesale Power Markets

The December 1st Technical Conference had three objectives for its panel sessions: first, drivers and issues to wind energy participation in wholesale markets; second, planning, grid operation and utilization to account for wind and other emerging technologies; and third, OATT-services and pricing issues faced by wind generators.

The main theme of the conference revolved around tariff reform and how the FERC could make Order No. 888's *pro forma* tariff [68] more "wind friendly." The subjects raised most often by panelists and by audience comments were the

63. The PTC lapsed in 2000, 2002, and 2004, with related drops in installed wind projects in those years.

64. Steve Zwolinski, President of GE Wind Energy, stated that GE Wind laid off nearly 3,000 skilled workers after waiting seven months for the PTC to be extended beyond the end of 2003. During those months, GE Wind spent $500 million on manufacturing wind turbines and generators for which it had no customers. When the PTC was restored in November 2004, GE Wind sold its inventory within two days, but had major problems and expenses rehiring its skilled employees and reopening its closed plants. Steve Zwolinski, President, GE Wind Energy, Remarks at the American Council on Renewable Energy Conference (Dec. 7, 2004).

65. Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005). Sen. Ken Salazar (D-CO) introduced S. 1093, The Research and Development Investment Act, S. 1093, 109th Cong. § 3(a) (2005), to extend the wind PTC through January 1, 2011. The Foley-Pomeroy bill, H.R. 1511, 109th Cong. § 1 (2005), would extend the wind/renewable energy PTC through December 31, 2010.

66. PURPA required utilities to sign agreements with some small wind producers as qualifying facilities (QFs), at their "avoided cost" of building additional generation. Many early QF contracts are expiring; all three California investor owned utilities have said they will renew existing wind QF contracts only if they are able to negotiate more favorable rates; the cost of new wind is below that of existing QF contracts. *California Energy Markets*, March 15, 2005.

67. The Union of Concerned Scientists (UCS) and others approached Massachusetts Department of Telecommunications and Energy (DTE) with such an amendment in January 2005. Telephone Conversation with UCS (April 2005).

68. "*Pro forma* tariff" means that the FERC provided standardized language that a transmission provider can use; if they wish to amend it, they would submit it to the FERC for approval. It is also commonly referred to as the "Open Access Transmission Tariff" or "OATT".

need to address punitive imbalance charges levied against wind, the need for tariff reform and new transmission products other than the two described under Order No. 888, the need to find ways to use the existing transmission system more efficiently until the day when more transmission is built, and the need for better forecasting.[69] The issues raised by participants, audience members, and Commission staff gave rise to a number of initiatives discussed elsewhere in this article, including:

- A Proposed Rule on Imbalance Provisions for Intermittent Resources (see Section VI),
- Bonneville's Conditional Firm Transmission Service Proposal (see Section IV), and
- Southern California Edison's Renewable Trunk-Facility proposal (see Section VII).

C. Conference Follow-Up

In its request for comments, the FERC noted that a number of "action items" were raised at the conference by the Commission staff or conference participants. Among them were whether the FERC should re-evaluate the imbalance penalties under Order No. 888's *pro forma* transmission tariff; how the FERC and the industry could make more efficient use of existing transmission facilities with potential new wholesale transmission services; if the FERC should examine the possibility of adopting a new transmission interconnection category—a "Renewable Resource Trunk Facility"—that would not be treated as a generation-tie and which would be rolled into rates; how the FERC could work with the states on their preferences for Renewable Portfolio Standards; what special issues Native American tribes face in developing wind energy and on what issues should the FERC consult with them on wind development; and if the FERC should help to establish capacity credit criteria or advocate a method of determining capacity value of intermittent resources.[70]

The FERC's initial efforts followed two lines of tariff reform: resolving whether imbalance penalties frequently assessed on wind generation under Order No. 888's OATT were unduly discriminatory, and developing new transmission services that would allow for more efficient use of existing transmission capacity for all sources of generation. The Commission undertook extensive outreach with wind industry participants and the public for feedback on issues which were raised at the conference and how best to facilitate wind's integration into the transmission system.[71]

69. Forecasting for day-ahead and hour-ahead scheduling of wind takes into account several factors such as wind speed and direction, ambient temperature, humidity, and barometric pressure. Forecasts become increasingly accurate as they approach hour-ahead.

70. Notice Requesting Post-Technical Conference Comments, *Assessing the State of Wind Energy In Wholesale Electricity Markets*, FERC Docket No. AD04-13-000 (2004).

71. Press Release, Fed. Energy Regulatory Comm'n, Comm'n Proposes New Rules Addressing Wind Energy in Open Access Tariff, Docket Nos. RM0510-000 and AD04-13-000 (Apr. 13, 2005).

IV. BONNEVILLE'S CONDITIONAL FIRM PROPOSAL

A. *What Is the Need for Conditional Firm Transmission Service?*

Wind developments need long-term transmission contracts in order to arrange financing for their projects, but under "OATTs" required by the FERC, there are only two transmission products available to wind developers: long-term firm, when the transmission owner can provide firm transmission under all circumstances when the system is not generally curtailed, and short-term non-firm, in which the customer is subject to curtailment whenever necessary to meet the transmission demands of the long-term firm customers.[72] Typically, however, short-term non-firm service is only available for less than a year, and does not entail the right to rollover such service for succeeding years, as do long-term firm service contracts. Short-term non-firm service, while it may provide adequate service, is not attractive to investors and lenders for project financing of wind developments because it does not provide a basis for projecting long-term revenues from projects.

B. *Background of the Proposal*

The Renewable Northwest Project (RNP) and West Wind Wires (WWW) both participated in the Rocky Mountain Area Transmission Study (RMATS). RMATS grew out of a call by the Western Governors' Association in response to the 2000–2001 energy market crisis in the western states to develop a preliminary transmission study and state siting protocol to address electric transmission needs in western power markets.[73] The RMATS Report, presented to the Western Governors' Association in September 2004, concluded, among other things, that making the most efficient use of existing transmission infrastructure is a prerequisite for persuading regulators, political leaders, and the public that new transmission construction is truly needed. The Report noted that there is not year-round Available Transmission Capacity (ATC) on many transmission paths in the Western Electric Coordinating Council (WECC) region, but there were paths that were congested for only twenty to fifty hours per year, and that wind generators could use such capacity to move substantial amounts of wind energy if the transmission owners would provide some form of service that was intermediate between short-term non-firm and long-term firm service.[74] The RMATS study group recommended that transmission owners and operators develop two more transmission service products that are intermediate between long-term firm and short-term non-firm, namely long-term "conditional firm," and "priority non-firm" services.[75]

At the December 1st Conference, a Bonneville representative said that it had been in consultation with RNP and WWW about developing such tariff provisions for its OATT, was planning a two-day workshop in February 2005, to

72. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities*, 75 F.E.R.C. ¶ 61,080 App. D (1996).

73. Comments of Beth Soholt, Director, Wind on the Wires, *Assessing the State of Wind Energy in Wholesale Electricity Markets*, FERC Docket No. AD04-13-000 (2004).

74. The RMATS studies of certain congested transmission paths indicate that periods of maximum wind generation potential are found in periods when transmission is not physically congested. *Id.* at 2–3.

75. WYOMING PUBLIC SERVICE COMMISSION, ROCKY MOUNTAIN AREA TRANSMISSION STUDY (2004), *available at* http://psc.state.wy.us/htdocs/subregional/FinalReport/reportcover.pdf.

discuss the details of such proposals, and hoped to have FERC involvement in that workshop. Accordingly, the FERC created a new docket to consider such proposals,[76] and participated in a Technical Workshop on that topic in Portland, Oregon, on March 16–17, 2005.

Under the proposal, conditional firm service would be like long-term firm, except the transmission provider would specify certain periods of the year when its expectations of transmission congestion require the curtailment of conditional firm service prior to any curtailment of firm service customers. For example, a conditional firm customer might receive firm service for ten or eleven months of the year, but be subject to curtailment prior to curtailment of firm service customers during one or two specified months of the year, when transmission congestion is most likely.

The transmission provider could also specify a cap on the number of hours a conditional firm customer would be curtailed prior to curtailment of firm customers during the specified months of conditional firm service. If curtailment of firm service customers became necessary during the months that conditional firm customers are assured firm service, or after the maximum number of hours specified for curtailment during a month when conditional firm service is conditional, the conditional firm customers could be curtailed at the same time (not prior to), and in the same proportion, as all other firm customers. Conditional firm service would only be offered to a customer who has requested firm service, but cannot receive it due to the lack of ATC on the path in question, and conditional firm customers must be willing to accept firm service when and if it becomes available.[77]

Long-term priority non-firm service would be subject to curtailment of service prior to any curtailment of firm or conditional firm service customers, but only after curtailment of all other non-firm service customers. Moreover, priority non-firm service would be offered for a term of one year or longer, unlike the limitation of non-firm service to terms of less than a year.[78]

The intriguing feature of Bonneville's possible offering of conditional firm~~,~~ is that it might provide the virtual equivalent of firm service for most of the time that wind generators need the transmission capacity. The periods of time when BPA's firm transmission commitments preclude offering new firm service to wind may largely coincide with the periods when wind generation is least likely. But, even without such a happy coincidence, if wind generators could be offered long-term service that was virtually firm for a substantial part of the year, with a defined period and defined number of hours during which wind would be curtailed prior to curtailment of firm service customers, the ability of developers to finance wind generation could be significantly enhanced.

C. Comments Filed After Technical Workshop

In its post-conference filing, the American Public Power Association (APPA) argued that the transmission providers should not guarantee a limited number of curtailment events or hours. According to APPA, such guarantees are

76. Notice of Final Agenda for Technical Workshop, *Potential New Wholesale Transmission Services*, FERC Docket No. RM05-7-000 (2005) [hereinafter *New Wholesale Transmission Services*].

77. *New Wholesale Transmission Services*, *supra* note 76, at attachment C (containing BPA's draft proposal).

78. *Id.*

difficult to make even to firm customers, and providing such guarantees to conditional firm customers would discriminate against firm customers without such guarantees. APPA also asserted that conditional firm service may be feasible for BPA because of the large amount of hydroelectric facilities whose output can be quickly varied in response to available wind energy, and where pumped storage hydroelectric projects would permit excess wind energy to be "stored" by using it to fill pumped storage reservoirs.[79] However, APPA doubted that other regions of the country without so much hydroelectric capacity could integrate with wind energy as easily, and that the conditional firm service that BPA is considering may not work in other regions.[80]

Southern Company's post-workshop comments urged the Commission not to apply BPA's conditional firm proposal to other transmission providers in different circumstances (i.e., not in the Southeast). Southern also questioned the reliability and accuracy of the "probabilistic analysis" that BPA's proposal entails, rather than the conventional "deterministic method." Southern foresaw significant problems establishing where a request for conditional firm service would fit into the "queue" along with requests for firm and non-firm service, and determining when conditional firm service should be curtailed in relation to firm service, both point-to-point firm and network service firm.[81] Southern was also concerned that providing conditional firm transmission for a lower rate than firm, but guaranteeing it firm service on the basis of probabilistic analysis that may prove to be inaccurate, will result in firm transmission customers subsidizing conditional firm customers, or retail ratepayers bearing the costs associated with possible decreases in available firm transmission service.[82]

AWEA *et al.* responded to some of these comments, clarifying that any cap on the number of hours that a conditional firm customer would be curtailed meant a cap on the number of hours that the customer would be curtailed while firm customers are not being curtailed. There would be no limits on the number of hours or events of curtailment of conditional firm pro rata with curtailment of firm customers at the same time. As explained in its responsive comments, AWEA *et al.* viewed conditional firm as enabling incremental amounts of new generation to interconnect to the grid, even though there may not be enough new generation capacity to justify construction of new transmission facilities. Furthermore, AWEA *et al.* anticipated that revenues from conditional firm would be greater than existing levels of revenue from short-term firm and short-term non-firm, even though conditional firm service may partially displace requests for short-term service, and mitigate future rate increases for all

79. A hydroelectric pumped storage project pumps water from one level to a reservoir at a higher elevation, usually at night when system demand is at its lowest, and then releases the water through turbines that generate electricity and discharge the water back into the lower level during the periods of peak demand. The amount of energy consumed pumping water to the upper reservoir exceeds the amount produced by releasing it at the lower level, but the project can provide significant economic value by providing energy to meet a system's peak demand.

80. Initial Comments of the American Public Power Association, *Potential New Wholesale Transmission Services*, FERC Docket No. RM05-7-000 (2005).

81. The "queue" is the chronologically ordered list of pending applications for interconnection of generation resources to a transmission system. The transmission operator processes such applications by performing the studies necessary for such interconnections in the order the applications are received.

82. Comments of Southern Companies Concerning March 16–17, 2005 Technical Workshop, *Potential New Wholesale Transmission Services*, FERC Docket No. RM05-7-000 (2005).

customers by more efficient and economical use of existing transmission capacity.[83]

D. These New Transmission Services Could Facilitate Wind Development

The electric utility grid system is already configured to optimize the use of energy from other generation sources with their own unique characteristics of productivity. For example, all of the other generation and transmission resources of a system are operated to accommodate the need of a nuclear power plant to run continuously at relatively high capacities. Coal-fired generation facilities exhibit some of the same characteristics, having long ramp-up and ramp-down times. Increasing development of wind generation raises the issue of how far the existing participants in the electric system can or should go to accommodate wind generation's unique characteristic of intermittency.

Customers who may have benefited from an inexpensively priced interruptible (non-firm) transmission service that is "firm" for all practical purposes, may find the reliability, and hence value, of that interruptible service diminished by accommodating the higher priority of conditional firm customers. They may be curtailed under circumstances where, but for the rights of conditional firm customers, they would not.[84] Firm transmission customers may find that when they are curtailed, the extent of their curtailment may be greater because of the need to provide conditional firm customers a pro rata share of the curtailed service. Thus, the services of other transmission customers may be somewhat degraded by the provision of conditional firm service. So what should the rate be for conditional firm, and the other services it may degrade?

These issues are appropriate topics for cost allocation and rate design proceedings, issues with which the FERC and the electric utility industry are well familiar. The fact that cost recovery for new and existing services has to be comprehensively evaluated does not provide an argument against offering a new service. There may be persuasive arguments against requiring conditional firm or high-priority non-firm services to be offered throughout the country, but the proposals under consideration in the Northwest would increase the efficient use of BPA's existing transmission facilities by providing new services that meet the needs of potential wind generation customers and optimize the use of existing transmission capacity.

V. IMBALANCE PROVISIONS FOR INTERMITTENT GENERATORS—PROPOSED RULE

A. Why was a Separate Imbalance Schedule for Intermittent Resources Needed?

When Order No. 888 rules were written in 1996 as part of the OATT,[85] they

83. Comments of the American Wind Energy Association, the Renewable Energy Northwest Project and West Wind Wires in Response to Other Comments Submitted on the Technical Workshop Held March 16–17, 2004, *Potential New Wholesale Transmission Services*, FERC Docket No. RM05-7-000 (2005).

84. Such customers should not be precluded from receiving conditional firm service if non-firm service no longer meets their needs.

85. Order No. 888-A included a schedule for *energy* imbalances, but made no provision for *generator* imbalances. Energy imbalances are the differences between what "load" says it will take and what it really takes in a given hour. It is the energy imbalance service (Schedule 4), which has a bandwidth of +/- 1.5%.

were designed for large generators with controlled fuel input and relatively precise scheduling ability, rather than for small wind plants whose fuel input is variable. In 1996, there were 1,696 MW of wind generation installed in the United States; since then, wind resources have grown at an annual average rate of about 20% to 6,740 MW at the end of 2004.

Generator imbalances are the differences between the day-ahead scheduled energy from a generator's control area, and the amount of real-time energy generated. The penalty for generator imbalances was intended to promote good scheduling practices. But penalties had become punitive, rather than economic, for wind generation. Comments subsequent to the December Conference revealed that market participants were not consistently applying the imbalance provisions.

Commissioner Suedeen Kelly noted in her comments when the proposed rule was announced that imbalance penalties were intended to have generators balance output with scheduled production, but for wind generators the source of the deviation is the changing weather. The proposed rule will help wind generators avail themselves of the "OATT." The FERC reiterated that this rule will allow wind generators—as well as other intermittent resources—"to compete on a level playing field and become a larger part of our nation's energy portfolio . . . by removing barriers that affect intermittent resources' access to the transmission grid."[86]

B. What are the Provisions of the Proposed Schedule?

The NOPR would require transmission providers to append the imbalance provisions as a separate schedule to their standard transmission service tariffs.[87] Specifically, it proposes a deviation "bandwidth" for intermittent resources of plus or minus 10% for the difference between the amount scheduled and actually generated each hour.

Under the proposed rule, deviations within the bandwidth would be priced at a transmission provider's system incremental (or reduced) cost at the time of deviations. Deviations outside the new bandwidth would be priced at 110% (plus) or 90% (minus) a transmission provider's system costs during the hour.[88] Importantly, the NOPR reiterated that the existing tariff provisions, which had often been practiced in the breach, allow generators to modify their schedules up to twenty minutes before the hour at no charge, thus minimizing imbalances.

At the December Conference, participants debated the merits of the Commission's requiring wind generators to use state-of-the-art forecasting techniques. Rather than defining what could become a moving target, the

Order No. 888-A *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Service by Public Utility: Recovery if Stranded Costs by Public Utilities and Transmitting Utilities*, F.E.R.C. STATS. & REGS ¶ 31,048 (1997), 62 Fed. Reg. 12,274 (1997) (to be codified at 18 C.F.R. pt. 35).

86. Transcript of Open Commission Meeting, *In re* Consent Markets, Tariffs and Rates—Electric, at 146–47 (2005), *available at* http://www.ferc.gov/EventCalendar/Files/20050421080112-transcript.pdf; Press Release, Fed. Energy Regulatory Comm'n, Comm'n Proposed New Rules Addressing Wind Energy in Open Access Tariffs, Docket Nos. RM05-10-000 an AD04-13-000 (Apr. 13, 2005).

87. The NOPR would create a new generator imbalance service schedule for intermittent resources under the *pro forma* open access transmission tariff (OATT) in Order No. 888. *Imbalance Provisions, supra* note 10.

88. Notice of Proposed Rulemaking, *Imbalance Provisions for Intermittent Resources Assessing the State of Wind Energy in Wholesale Electricity Markets*, F.E.R.C. STATS. & REGS. ¶ 32,581, 32,134, 70 Fed. Reg. 21,349 (2005).

Commission declined to set a forecasting standard. Instead, it believed that the revised deviation bandwidth would create the incentive for wind generators to adopt the best available forecasting techniques. Thus, the penalties become economic rather than punitive, while still promoting better scheduling by intermittent generators.

C. How Did Industry React in its Comments?

Comments were due by May 26, 2005. At the time this article was written, forty-six comments had been submitted by interested parties and were being reviewed by staff. The California ISO and other commenters described how better forecasting has or can improve their ability to integrate wind power into their systems and minimize deviations. CAISO responded in support of the proposed rule, while touting the provisions of its FERC-approved Participating Intermittent Resources Program (PIRP) as superior. Specifically, it noted that "[the] NOPR correctly recognizes that weather-driven conditions beyond the intermittent generator's control will cause frequent deviations between the generator's output and its schedule."[89] It urged the Commission to use its model, which exempts intermittent generators from hourly imbalance penalties, but settles imbalances by netting them over a month. CAISO said it does not use an "arbitrary deviation band," because it assumes that "[v]ariability will be greater in some hours than in others . . . ."[90] In addition, by having intermittent generators, who have chosen to participate, pay a fee to support a system-hired independent forecaster, CAISO believes the system receives professional, near real-time energy forecasts.[91]

VI. FINAL RULE ON INTERCONNECTION OF SMALL GENERATORS (ORDER NO. 2006)

On May 12, 2005, the FERC issued a rule to standardize procedures for the interconnection of generators no larger than 20 MW. This rule was the culmination of a process begun in August 2002, when FERC issued a Small Generator Interconnection Advance Notice of Proposed Rulemaking.[92] The goals of the rule were to remove barriers to the development and interconnection of small generation while preserving the safety and reliability of the nation's electric system.[93] The adoption of national standards, as noted in the discussion of the large wind interconnection rule, limits opportunities for transmission utilities to favor their own generation, removes unfair barriers to entry for small generators by reducing costs and time, and encourages investment in generation and transmission infrastructure where needed.[94] The Commission's intent was to

89. Opening Comments of the California Independent System Operator Corporation in Response to Notice of Proposed Rulemaking, *Imbalance Provisions for Intermittent Resources Assessing the State of Wind Energy in Wholesale Electricity Markets*, FERC Docket Nos. RM05-10-000 and AD04-13-000 (2005) [hereinafter Opening Comments CAISO].

90. *Id.*

91. Opening Comments CAISO, *supra* note 89.

92. Advance Notice of Proposed Rulemaking, *Standardization of Small Generator Interconnection Agreements and Procedures*, F.E.R.C. STATS. & REGS. ¶ 35,544, 67 Fed. Reg. 54,749 (2002).

93. *Standardization of Small Generator Interconnection Agreements and Procedures*, 111 F.E.R.C. ¶ 61,220 (2005); Order No. 2006, *supra* note 14.

94. Order No. 2006, *supra* note 14, at 31,413.

standardize the Small Interconnection Agreements and Procedures (SGIA, SGIP), as it did later for large generation in Order No. 2003.[95] The Small Generation Rule aimed to harmonize national standards with best practices already instituted by the states and by the National Association of Regulatory Utility Commissioners (NARUC), and to minimize barriers to connecting new technologies to the transmission system.

Chairman Pat Wood III noted in announcing the rule (Order No. 2006) that:

> [T]oday's rule takes us a step closer to truly non-discriminatory, competitive bulk power markets. Advances in technology have led to a growing industry of small power plants that offer economic and environmental benefits. Standardization of interconnection practices across the nation will lower costs for small generators, help ensure reliability, and help ensure reasonably-priced electric service for the nation's wholesale power customers.[96]

The Commission decided not to make special provisions for wind energy in the rule. At the September 24th Technical Conference on Wind Energy, staff asked panelists whether the technical standards in the Appendix G "grid code" should apply to small generators as well as to large ones. They responded that those capabilities—such as low-voltage ride-through—were not needed for small generation facilities, whether wind powered or not. The SGIA contains the same provisions as the LGIA regarding wind, absent the recently approved Appendix G. The Small Generator Rule concluded that the reliability requirements proposed for wind powered facilities over 20 MW are not necessary for grid reliability or safety, and are not needed for small wind generating facilities.[97]

VII. TRANSMISSION FACILITIES TO TEHACHAPI WIND RESOURCE AREA[98]

A. *Southern California Edison's Petition*

Southern California Edison (SCE) filed a petition for a declaratory order with the FERC on March 24, 2005, pertaining to its plans to build transmission

95. *See* Order No. 2006, *supra* note 14.

> "Order No. 2003 . . . adopted two documents that are to be used for the interconnection of Large Generating Facilities—the Large Generator Interconnection Procedures document and the Large Generator Interconnection Agreement. The LGIP describes how the Interconnection Customer's Interconnection Request (i.e., application) is to be evaluated from an engineering perspective using a four-step process. These are the scoping meeting, the feasibility study, the system impact study, and the facilities study. The purpose of the evaluation is to determine the impact the proposed interconnection will have on the Transmission Provider's electric system and identify new equipment and modifications needed to accommodate the interconnection. The LGIA, which is signed after the proposed interconnection has been successfully evaluated using the provisions contained in the LGIP, describes the legal relationships of the Parties, including who pays for equipment modifications to the Transmission Provider's electric system. The SGIP and SGIA we adopt in this Final Rule serve the same purposes as the LGIP and LGIA."

Id. at 31,416.

96. Press Release, Fed. Energy Regulatory Comm'n, Comm'n Issues Standard Rule for Small Generator Interconnection; Action Will Facilitate Needed Infrastructure Development, Docket No. RM02-12-000 (May 12, 2005).

97. Order No. 2006, *supra* note 14, at 31,415.

98. One of the co-authors, Carol White, is on the FERC staff at the time this is written, and SCE's Tehachapi filing was pending before the Commission, although she was not working on that proceeding. Given these circumstances, White excluded herself from participation in writing the discussion of SCE's Tehachapi filing.

facilities to the Tehachapi Wind Resources Area, north of Los Angeles, California.[99] According to the Tehachapi Collaborative Study Group, created by the California Public Utility Commission (CPUC), the Tehachapi region is one of the richest wind energy resources in California.[100] The wind generation potential in the Tehachapi region is believed to be in excess of 4000 MW, an amount of power equal approximately to all of the state's nuclear capacity. However, while there are many indications of wind developments being planned for this Tehachapi region, and several developers have requested SCE to perform system impact and facilities studies for Tehachapi sites, no developer of a Tehachapi site had executed a formal interconnection agreement with SCE at the time of the filing of its petition for declaratory order with the FERC.

Nevertheless, the CPUC ordered SCE to file an application to the CPUC for a certificate authorizing construction of the first phase of a series of three Tehachapi transmission upgrades and also to seek authority from the FERC to recover the costs of the transmission facilities.[101] SCE's ensuing petition requested four rulings. SCE asked that the costs of three transmission projects, which it denotes the Antelope Transmission Projects, be granted "rolled-in" rate treatment, meaning that those costs would not be charged to (or directly assigned to) the wind generation facilities that will be connected to the grid system by means of these new facilities, but would be recovered by spreading those costs to all customers on the CAISO system. Secondly, SCE requested assurance of recovery of the reasonable and prudently incurred costs of these projects regardless of whether all of the forecasted new wind generators actually commence operations. Thirdly, SCE requested assurance of recovery if the potential generation does not develop as forecast and SCE must abandon or cancel one or more of these projects. Finally, SCE requested that the Commission declare that the third segment of the Antelope Transmission Projects, new high-voltage, trunk-line transmission facilities necessary to interconnect large concentrations of potential renewable generation resources to the grid, be recognized as a new category of transmission facilities eligible for rolled-in rate treatment, and that this segment be placed under the CAISO's operational control to provide open, non-discriminatory access to those facilities.[102]

The FERC acted on SCE's Tehachapi filing July 1, 2005, granting SCE's requests in part, but denying the request to recognize a new category of trunk-line transmission facilities for large concentrations of renewable energy, and denying the rolled-in rate treatment for the segment of SCE's proposed facilities closest to the Tehachapi wind resource area.

B. *Why SCE Requested Advance Rulings From the FERC*

SCE said these requests were made because of FERC precedents that impose a risk on SCE, as the owner of the new transmission facilities, of a denial

99. *Southern California Edison Co.*, 112 F.E.R.C. ¶ 61,014, 61,137. "Tehachapi" is the local Native American word for "strong winds." (Comments of PPM Energy, Inc., p.3).

100. California Energy Commission Filing, Tehachapi Collaborative Study Group Report, Southern California Edison Co., FERC Docket No. EL05-80-000.

101. Petition of Southern California Edison Co., Southern California Edison Co., FERC Docket No. EL05-80-000 (citing CPUC proceeding and Decision 04-06-010).

102. 112 F.E.R.C. ¶ 61,014.

of the full recovery of the costs of these projects. First, there was a risk the FERC might rule that the facilities, or part of them, are not integrated with the transmission network and should have been paid for by the developers of the generation as generation-tie lines.[103] If deemed to be generation-tie lines, their costs could not be included for recovery as part of SCE's transmission revenue requirement or in the CAISO's "high voltage transmission access charge," and thus not be spread over the widest group of California ratepayers. The FERC's ruling recognized that two of the three segments of the Antelope Project would be part of California's integrated transmission network, consisting of 43.4 miles of 500 kV transmission lines.[104] Furthermore, there was a risk under certain precedents that the FERC might ultimately conclude that the transmission facilities were overbuilt, if all of the projected wind generation facilities at Tehachapi are not built, and SCE might face the risk of only partial recovery of its investment.[105] The FERC deferred a ruling on this issue until after the CPUC issues the necessary certificates of public convenience and necessity.[106] Finally, there was a risk that SCE might be denied recovery of 50% of its prudently made investment in any of these facilities that might be abandoned,[107] or whose construction is cancelled before completion, due to a failure of wind generation to be developed as expected.[108] The FERC order of July 1 assured SCE of recovery of its prudently made investment in Segments 1 and 2 of the Antelope Project in such event, and concluded that the request as to Segment 3 was moot, since Segment 3 was found to be a generation-tie facility, ordinarily financed by the generators.

SCE asserted that the first two segments of these projects would be integrated into the transmission network, and thus entitled to rolled-in rate treatment under existing FERC precedent, but the third segment would be a high-voltage generation-tie line, not integrated into the transmission network, and not ordinarily eligible for rolled-in rate treatment, nor subject to operational control of the CAISO. Nevertheless, SCE asked that rolled-in treatment for the generation-tie segment be approved as a new category of transmission facilities—new high voltage, trunk-line transmission facilities necessary to connect large concentrations of potential renewable generation resources located a reasonable distance from the existing grid. Despite its characterization of the first two segments of these projects as integrated transmission network facilities, SCE sought advance FERC approval of rolled-in rate treatment because of possible challenges to this treatment because they would be built primarily for

103. Order No. 2003, *supra* note 3; 112 F.E.R.C. ¶ 61,014, 61,138. FERC's July 1 order noted that Order No. 2003 does not preclude electric utilities from financing the costs of generation-tie facilities.

104. These segments would be designed to be 500 kV lines, but would be built and operated initially as 220 kV lines.

105. Costs of facilities that are not used and useful to providing the utility service may not be recovered through cost-based rates. Tenn. Gas Pipeline Co. v. FERC, 606 F.2d 1094, 1123 (D.C. Cir. 1979), *cert. denied*, 445 U.S. 920 (1980). It is an issue of fact whether facilities that are not fully utilized are used and useful. *Williston Basin Interstate*, 48 F.E.R.C. ¶ 61, 137 (1989).

106. A certificate of public convenience and necessity is the state's "license" to a public utility to build facilities that the regulatory commission has found are needed to provide utility service. Applications for such certificates were pending before the CPUC when the FERC issued its July 1 order.

107. Abandonment means taking a utility's facility out of service, usually requiring prior regulatory approval.

108. Opinion No. 295, *New England Power Co.*, 42 F.E.R.C. ¶ 61,016, 61,083, *reh'g denied in relevant part*, 43 F.E.R.C. ¶ 61,285 (1988); *Public Service Co. of New Mexico*, 75 F.E.R.C. ¶ 61,266, 61,859 (1996).

the benefit of certain generators.

C. National Grid's Support and Its Generic Policy Proposal

National Grid filed comments in support of SCE's proposal, but proposed a broader principle of providing transmission owners cost recovery assurances such as those SCE is seeking.[109] National Grid urged the Commission to establish minimum standards for a comprehensive system planning process and encourage or require transmission companies to adopt such processes. According to National Grid, requiring the use of a robust, proactive planning process would be far superior to the current practice of transmission owners responding on a case-by-case basis to specific generator requests for interconnection. The primary shortcoming of this ad-hoc procedure is exemplified by the situation SCE faces at Tehachapi, where the initiation of transmission infrastructure construction might be driven by the need to serve new entrants to the market, but the absence of sufficient transmission capacity presents an insurmountable obstacle to participation of such new entrants.

National Grid asserted that a properly designed regional planning process would contain safeguards to mitigate the risk of building unnecessary transmission capacity. The allocation of the costs of such facilities, whether rolled-in as transmission network facilities or directly assigned to generators, and the company's assurances of cost recovery, should be resolved before the transmission company builds the new infrastructure. Such a planning process should be overseen and administered by an independent entity to ensure that the analysis and decision-making are not skewed toward the interest of any particular market participant. The planning process should entail a cost-benefit analysis to determine whether a particular project is expected to provide regional benefits, and the cost-benefit analysis should assess the likelihood that proposed facilities would be fully utilized and discount the expected value of a facility based on the probability that some of the new entrants may not emerge.

Most importantly, National Grid argued, the cost allocation methodology and cost recovery principles for a new transmission project should be based on clear, pragmatically determined categories and be determined *ex ante,* before construction of the facilities.[110] The cost allocation should be done on the basis of an objective functional analysis of beneficiaries of the facilities, and not be subject to re-evaluation over the life of the project.[111]

D. The Commission Decision

The FERC granted rolled-in rate treatment of the costs of the 43.4 miles of high-voltage transmission lines that would arguably provide benefits to system reliability, regardless of how much new wind generation facilities are built at Tehachapi. However, the Commission denied rolled-in rate treatment to the costs of the 34.4 miles of transmission lines and two substations that would connect new wind generation facilities in the Tehachapi region to the

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109. National Grid has divested itself of nearly all generation, and operates almost exclusively to deliver energy.

110. *Ex ante* means "before the fact." Here it means asking for a Commission ruling before taking an action.

111. National Grid's Motion to Intervene, Southern California Edison Co., FERC Docket No. EL05-80-000 (filed April 14, 2005).

transmission facilities in Segments 1 and 2 of the Antelope Project, and thus to the CAISO-operated grid system.[112] The FERC concluded that the Segment 3 facilities were generation-tie facilities, not network upgrades (which SCE conceded in its petition) and thus not entitled to rolled-in rate treatment under the policies of Order No. 2003. Moreover, the FERC said that SCE had failed to show how all the users of the CAISO-controlled grid would benefit from these facilities, which, if shown, would justify an exception to the rule that the generators and their customers, as sole beneficiaries, must bear all the costs of such facilities.[113]

The Commission noted that SCE could voluntarily finance these facilities—that Order No. 2003 did not require that it assess the costs of generation-tie facilities to the generators that utilize such facilities to connect to the grid system—and that California legislation requires the CPUC to authorize the costs of such facilities through SCE's retail rates, if they are not recovered through FERC-jurisdictional transmission rates. Thus, it is possible the facilities in question will be built despite the Commission's ruling. The State of California has required by law that its electric utilities acquire a certain percentage of their power from renewable energy resources, because such reliance in part on renewable energy is in the public interest. However, the record shows that SCE has already acquired 18% of its power from renewable resources (out of the statutory goal of 20%). If built under these circumstances, the retail ratepayers of SCE would bear all the costs of the Segment 3 facilities, which may be used primarily to meet the RPS requirements of other California electric utilities.

Despite any concerns about the equity of the cost allocation, the FERC order provided advance rulings on most of the crucial issues that SCE's petition raised, thus removing some of the regulatory uncertainty that sometimes constitutes a barrier to construction of needed transmission facilities. Such actions by the FERC in the future should facilitate the development of needed transmission infrastructure to get energy from the generators to the loads.

VIII. Integrating Wind Generation into a Competitive Electric Power Market

A. *Two Different Kinds of Electric Markets*

There are essentially two different types of tariff regimes in this country.[114] The FERC Order No. 888 Pro-Forma Tariff ("Type I"), which is used by transmission providers in the West (except for California), lower Midwest, and Southeast. Regions with "Type I" tariffs make roughly 40% of electric sales in this country. Type I tariffs provide transmission service either as Network service or Point-to-Point service.[115] Point-to-Point service is from one

112. Two commissioners of the four that would have allowed rolled-in treatment of Segment 3 facilities, but one commissioner characterized her position as a concurrence, thus breaking a deadlock that would have prevented any Commission action on SCE's petition.

113. *See also* Darrell Blakeway, *Tehachapi Wind Power Setback Has Nationwide Implications*, NATURAL GAS & ELEC., Sept. 2005, at 11 (elaborating on the significance of the Tehachapi decision).

114. James H. Caldwell, Jr., former Policy Director of AWEA, and now with PPM Energy, Inc., describes these tariff types in his presentations at workshops and conferences on wind interconnection issues.

115. Network service is for customers referred to as "native load," who were historically the "captive customers" of vertically integrated electric utilities, and utilizes service from the system's whole portfolio of

designated point where power is taken from a specified generator to another designated point where the customer receives power. If there are problems either with generation sources or transmission paths, the Point-to-Point customer is subject to curtailment and cannot avail itself of the portfolios of network resources available to Network Service customers. Type I tariffs provide for physical transmission rights, either as "firm" or "non-firm" service. Type I service is generally provided within relatively small "control areas" in which generators and transmission facilities are dispatched by a single electric company. Delivery imbalances are settled administratively.

The other type of tariff regime is the "Type II" tariff, or the FERC "Standard Market Design" tariff. These are used in the mid-Atlantic, Northeast, Midwest, Texas, and California, and sales of electricity under those tariffs amount to about 60% of the nation's total sales. Under a Type II tariff, all resources are "pooled" in a common market. Transmission rights are designated "financial rights" rather than physical rights, and are sometimes referred to as "congestion rights." A central system operator dispatches generators and transmission facilities over a relatively large geographic area. Delivery imbalances are settled financially in spot markets. Customers under a Type II tariff may receive service even though there is transmission congestion somewhere between their generation provider and point of receipt by paying the system operator the costs of generation from plants on the customer's side of the congestion, and thus avoid curtailment. Customers with financial transmission rights or congestion rights can receive this redispatched service without having to pay the higher cost of the generators used to serve their load in lieu of their designated generation suppliers.

These two radically different tariff regimes characterize the difference between areas with Independent System Operators or Regional Transmission Organizations, and areas with vertically integrated electric utilities. The wind industry has long recognized that, generally, Type II tariffs are vastly superior for wind as compared to Type I tariffs.[116] Nevertheless, existing Type I tariffs can be significantly improved without altering their basic character. Commenters at the December Wind Conference suggested improvements such as an exemption for wind generators from imbalance penalties, offers of more flexible transmission products, such as "conditional firm," and permitting wind plants to be designated as "network resources" and to be dispatched by means of "dynamic scheduling."

The FERC has taken many steps to improve the Type I tariff. But electric utilities that have formed themselves into centrally dispatched Regional Transmission Organizations usually provide a better market for profitable development of wind resources than those utilities that are still outside such organizations.[117] So, continuing action by the FERC to encourage the formation

transmission and generation assets designated as Network Resources. Point-to-Point customers are those who are "wheeling" power from some independent generation source, using the vertically integrated utility's transmission facilities. A wheeling customer purchases power from some independent power source and uses the transmission and/or distribution facilities of the electric utility company to receive such power.

116. Comments of American Wind Energy Association, *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, FERC Docket No. RM01-12-000 (Nov. 15, 2002).

117. At Caldwell's presentation on Transmission Issues in the Windpower 2005 Pre-Conference Seminar on Fundamentals of Wind Energy (Denver, Colorado, May 15, 2005), a wind developer asked Caldwell about

of RTOs, or improvements to Type I tariffs to emulate the wind-friendly features of RTO regimes, would provide a more level playing field, and be more conducive to the development of wind resources.

B. Beyond the Tehachapi Petition

A regulatory system in which petitions like the SCE Tehachapi petition are the rule, not the exception, would go far toward eliminating the "regulatory uncertainty" that transmission owners often cite as a primary barrier to their willingness to invest in transmission facilities that would be clearly beneficial to their customers. If the appropriate state regulatory and citing authorities have been persuaded that construction of transmission facilities of a certain size and configuration are convenient and necessary to serve the public interest (i.e., have issued a certificate of public convenience and necessity authorizing the construction of such facilities), then the FERC could determine the appropriate rate treatment for such facilities before the transmission facilities are built.

The FERC could choose to initiate some procedure for evaluating a generic requirement that all transmission owners engage in robust transmission planning processes, similar to those in California for Tehachapi, whether or not they are members of Regional Transmission Organizations. Potential investors in new transmission facilities would be greatly assured if they could get advance FERC rulings on how the costs of facilities that are built on the basis of the outcome of such a planning process should be financed and recovered—by rolling their costs into the transmission revenue requirement, directly assigning them to new market entrants (generators), or by whatever financing arrangements are just and reasonable under the particular circumstances. Furthermore, the risks to applicant transmission owners could be reasonably reduced by *ex ante* determinations of whether it will be prudent for such facilities to be built, despite the risk of underutilization, cancellation, or abandonment.

Overshadowing the issues of tariff provisions and control of the electric grid, there is a lack of adequate investment in the grid itself. There is little disagreement about the fact that there has been a long period of serious underinvestment in transmission infrastructure. But there is no consensus on why. Some say it is lack of sufficient economic incentives for investment in facilities whose rates will almost always be subject to cost-of-service regulation. Even if a particular group of FERC or state commissioners may be highly supportive of incentive rates of return for infrastructure investments, there is always uncertainty about what rates of return future commissions will allow. Some say it is uncertainty about who will ultimately have to pay the costs of new infrastructure investment. Will it be the new generators who need to interconnect with the new facilities (and only their customers), all of the ratepayers of a particular electric utility, or the ratepayers of an entire region within an RTO? And will the generators requesting new interconnection facilities be liable only for cost of the facilities to the point of interconnection with the grid, or also for upgrades to the grid that will enable it to carry the increased loads caused by the interconnections? And some, such as SCE about the Tehachapi facilities, say it is the uncertainty about whether investors will be

some difficulties he was having arranging for interconnection with Entergy in East Texas. He commented that his site was only two miles from the boundary with ERCOT (Electric Reliability Council of Texas), Texas's intrastate RTO. Caldwell told him to quit dealing with Entergy and interconnect with ERCOT if possible.

subject to reduced recovery for transmission facilities that ultimately prove to be of greater capacity than needed, or for facilities where construction has been begun but cancelled, or completed but ultimately abandoned.

The FERC has reactivated its Pricing Policy for Efficient Operation and Expansion of the Transmission Grid proceeding,[118] as evidenced by the Technical Conference it conducted on April 22, 2005, and the initiation of a new proceeding consolidated with the older proceeding, Transmission Independence and Investment.[119] Moreover, a plethora of articles continue to appear urging various approaches to increasing investment in transmission infrastructure, and there appears to be a healthy industry-wide dialogue on these issues, as well as intensified regulatory interest. A survey of the various policies being advocated is beyond the scope of this article, but it is significant that the FERC is turning attention again to this seemingly intractable problem. It would be well worth the time and attention of wind developers and advocates of renewable energy to engage in this dialogue with a view toward fostering the robust transmission grid that is a *sine qua non* of significant progress in tapping the power of wind.

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"May the wind always be at your back."[120]

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118. *Proposed Pricing Policy for Efficient Operation and Expansion of Transmission Grid*, 102 F.E.R.C. ¶ 61,032 (2003).

119. FED. ENERGY REGULATORY COMM'N, TRANSMISSION INDEPENDENCE AND INVESTMENT, TECHNICAL CONFERENCE AND AGENDA, Docket No. AD05-5-000 (Apr. 14, 2005).

120. Traditional Irish blessing.