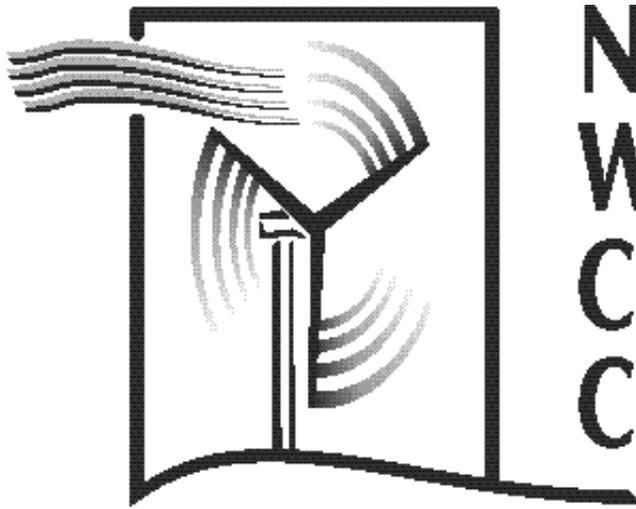


# Wind Energy System Operation and Transmission Issues Related to Restructuring



**NATIONAL  
WIND  
COORDINATING  
COMMITTEE**

**National Wind Coordinating Committee**

## **Wind Energy System Operation and Transmission Issues Related to Restructuring**

Wind and other renewable resources may be uniquely affected by new electric industry rules because of inherent characteristics such as their location dependence, intermittency and low capacity factor. This paper addresses system operation and transmission-related issues that may arise in various state and federal electric industry restructuring proceedings and that are of special importance to the operation of existing and the development of new wind energy resources in the United States.



The National Wind Coordinating Committee is a collaborative endeavor formed in 1994 that includes representatives from electric utilities and support organizations, state legislatures, state utility commissions, consumer advocacy offices, wind equipment suppliers and developers, green power marketers, environmental organizations, and state and federal agencies. The NWCC identifies issues that affect the use of wind power, establishes dialogue among key stakeholders, and catalyzes activities to support the development of an environmentally, economically and politically sustainable commercial market for wind power. More than 200 individuals from diverse sectors and wind resource areas across the country have contributed to the NWCC's collaborative efforts.

# **Wind Energy System Operation and Transmission Issues Related to Restructuring**

by

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National Wind Coordinating Committee  
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# INTRODUCTION

The purpose of this paper is to address system operation and transmission-related issues that may arise in various state and federal electric industry restructuring proceedings and that are of special importance to the operation of existing and the development of new wind energy resources. Wind and other renewable resources may be uniquely affected by new electric industry rules because of inherent characteristics such as their location-dependence, intermittency, and low capacity factor.

Given the current state and varied courses of these proceedings, as many potential transmission and system operation issues—both beneficial and detrimental to wind interests—will be discussed as can be perceived at this time, without limiting the focus to any single regulatory forum. Other issues—such as policy-driven preferences for wind resources or the incorporation of environmental externalities into the commodity price of electricity—are not addressed here because they do not exclusively pertain to new system operation and transmission rules.

In addition, many transmission issues affect wind developers differently, depending upon their ownership structure and position in the market. Nonutility wind companies, for example, may have a strong interest in promoting functional unbundling of transmission from generation, while utility wind developers may have a different interest. Generally, where interests in a transmission issue derive more from the company's competitive position in the market than from the wind technology itself, it has been excluded from the scope of this paper. Nonetheless, for issues that are common to all wind developers, the differences are considered between wind developers (nonutility, transmission-owning utility and transmission dependent utility) and discussed explicitly where appropriate.

Information for this paper was gathered by contacting individuals in the industry, reviewing materials from regulatory proceedings and surveying relevant trade and academic publications.

This paper on potential wind-specific transmission issues takes the following format.

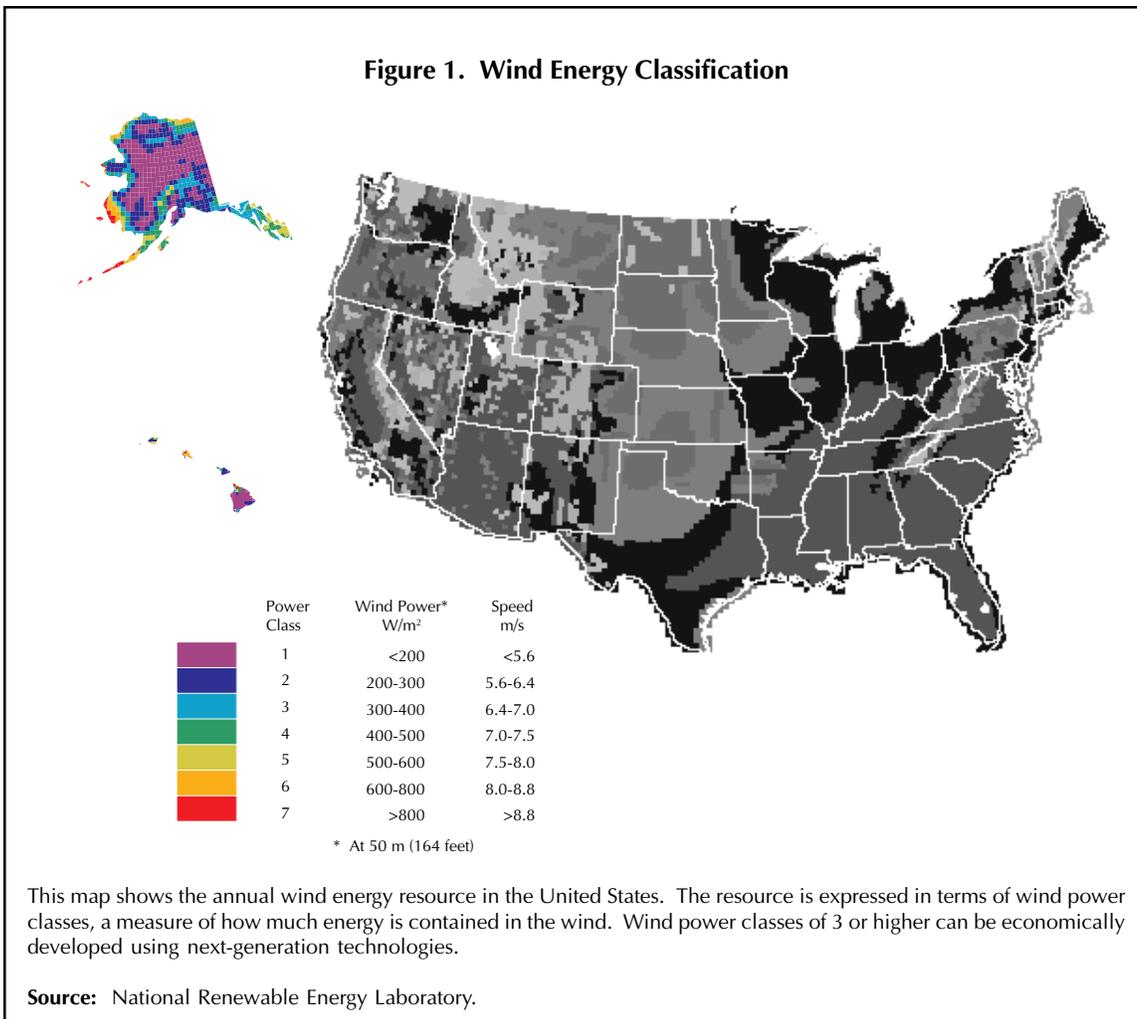
- First, characteristics of the wind resource are outlined that make it unique from more conventional generation facilities.
- The next section offers an overview of transmission pricing and scheduling issues. This overview specifically highlights generic issues that are elaborated upon in the detailed discussion sections that follow.

- Federal Energy Regulatory Commission (FERC) Order 888 is then addressed, with specific subsections about:
  - The Open Access pro forma tariffs and point-to-point transmission service;
  - The secondary market for transmission capacity; and
  - Pricing issues.
- The next section explains the open access same-time information system (OASIS) and outlines how wind projects will interact with the system.
- Ancillary services requirements are then discussed and the Federal Energy Regulatory Commission's (FERC) six categories of mandated ancillary services are explained.
- The capacity reservation tariff Notice of Proposed Rulemaking (NOPR) is explained in the next section, including how this could change the Order 888 tariff scheme and potentially affect utility-owned wind projects.
- Retail wheeling, flow-based pricing and the independent system operator power exchange proposals then are reviewed as alternative transmission policy approaches.
- Finally, a list of issues and topics is presented that deserve particular attention or additional review.

# NATURE OF THE RESOURCE

## Geographic Considerations

Availability of the domestic wind resource is limited to specific geographic regions and, within those regions, there may be degrees of variability. Figure 1 shows those regions in the continental United States that have good resource potential. Although good quality wind sites exist throughout the United States, the largest concentrations of high-quality resources typically are located far from large load centers.



This location-dependent characteristic of wind sets it apart from most generation facilities. Although some generation types such as hydro and coal-fired stations may also be located at significant distances due to limited resource availability, many conventional generation options do not face similar site restrictions. Because the more optimal wind resources are often distant from load centers, transmission-related costs can be an important consideration for wind project development.

The remote nature of wind also may provide certain transmission network benefits. Distributed resource benefits may occur when wind resources serve a local load, thereby avoiding or reducing the amount of additional power that must be transmitted through a transmission-constrained area. The benefit is greater when both the wind resource and the local load are remote from the conventional central plants. This concept is especially useful where the wind resource tracks the demand-driven transmission constraints. In concept, the wind resource would serve a portion of the native load customers who, because of system constraints or contingencies, are in an island or quasi-island situation.

### **Output Variability**

Wind is a naturally intermittent resource that must be approached by planners and system operators differently than conventional fossil-fired generation resources. Wind resources are characterized by diurnal and seasonal patterns that are unique to the location and topography of each site. Diurnal patterns are caused by the daily heating and cooling of the earth's surface. Seasonal variability is driven by temperature differentials and by local weather patterns.<sup>1</sup> These wind resource patterns affect each project's availability and output profile. For example, although two wind facilities may have the same capacity rating and annual energy production, the different wind regimes may result in very different hourly, daily and seasonal operating schedules. These natural variations may trigger different transmission-related costs associated with ancillary services—such as transmission scheduling, system dispatch, network stability, load-following and load-balancing—as system operators attempt to treat the wind generation like conventional resources.

The potential system costs imposed by wind generation will be mitigated if the penetration of wind is low compared to total system generation capacity and if it represents a small percentage of the local system control margin.<sup>2</sup> In circumstances where wind holds a higher generation market share, a simultaneous variation of output at a given time could affect the system to a greater degree and thereby impose costs in terms of necessary firming power, short-term scheduling requirements and additional unit commitments. Experience at established wind facilities shows, however, that the spatial diversity of turbines that cover thousands of acres effectively smoothes the hourly output profile for the resource as a whole.<sup>3</sup>

Network operational costs associated with a wind resource also will vary with the characteristics of the surrounding utility system. These characteristics include system size, load profile, control margin, available resource mix and whether the system has large hydro or other storage resources that provide instantaneous spinning reserve.<sup>4</sup> For example, the loss of wind generation may be more significant when the aggregated load profile is not made flexible with demand-side management resources.<sup>5</sup> If the control area is vast and includes a number of wind facilities, the aggregated wind resource could be treated like single disbursed generation facility. In that case the gradual loss of wind generation resources should not have network operation consequences identical to a

conventional plant tripping off-line because of some transient event, assuming that the wind resource is not serving a significant percentage of load.

The intermittent nature of wind is not necessarily a problem for network operations where the resource's availability parallels system demand. The characteristic of gradually increasing availability relatively matched with increases in local demand may serve to offset or delay the starting up of more marginal resources.

Expected wind production for a given wind resource can be estimated with a high degree of confidence on an annual basis, but the confidence level drops as the forecast is narrowed to a month, a week and a single hour. Techniques for forecasting wind energy production 24 hours in advance are not sufficiently developed to allow a high degree of confidence in specific facility output forecasts, although forecasting for the next hour can be done with some degree of confidence. However, current forecasting techniques may be sufficient to estimate the quantity and probable duration of firming power useful for participation in future power markets. Forecasting research is underway, however, and some in the industry believe that forecasting will improve as the market requires it.

### **Wind Plant Economics**

Wind facilities also face project economics that differ significantly from conventional resources. With fossil fuel generation, fuel costs comprise a relatively large fraction of total energy costs, whereas wind "fuel" is free. Therefore, wind projects' economic viability rests to a greater degree on the ability to recover their capital-related costs through operation. Transmission-related costs, driven in part by the location of the facility, clearly can increase the difficulties in project financing regardless of their characterization as capital or operating costs.

### **Resource Potential**

Studies have indicated that the United States could produce a significant amount of electricity from wind resources, including enough from class 3 and above resource areas to meet the total 1990 U.S. electric consumption. Only a fraction of this potential has been tapped, primarily in California. The wind in California produced 3.28 billion kilowatt-hours (kWh) in 1994, representing 1.5 percent of total electric retail sales in California.<sup>6</sup> Some estimations indicate that the United States could supply approximately 20 percent (about 560,000 million kWh/per year) of its electricity from the best resource locations with existing technology.<sup>7</sup> Exploitation of this potential has been limited by several factors, including initial technological barriers, environmental constraints, hesitancy on the part of utilities to integrate unfamiliar technology into the conventional resource mix and, most significantly for this paper, distances from transmission facilities and loads.

# TRANSMISSION PRICING AND SCHEDULING ISSUES—AN OVERVIEW

Whether in the context of FERC’s pro forma tariffs mandated by Order 888 or in the context of various restructuring proposals, transmission pricing and scheduling issues will have important implications for existing and new wind projects. Backgrounds and specific issues presented by Order 888 and the restructuring proposals are discussed in subsequent sections of this paper. However, as an introduction to both transmission approaches, this section briefly reviews certain generic transmission pricing issues of particular importance to wind technologies. As discussed below, most transmission pricing and scheduling issues of unique importance to wind development arise from the intermittent and site-dependent nature of the resource, as described previously.

Historically, firm transmission service has been sold on a take-or-pay basis, meaning that the generator must reserve transmission in advance and pay for what is reserved regardless of how much energy is actually scheduled and transmitted.<sup>8</sup> Moreover, once power deliveries are scheduled pursuant to a reservation of transmission, many tariffs impose substantial penalties if actual energy deliveries differ from the final schedule by a significant amount.

As a result of the intermittent nature of wind energy, it is much more difficult for wind operators to predict precisely how much transmission they will need to reserve and schedule.<sup>9</sup> Therefore, transmission pricing and scheduling protocols that require take-or-pay reservations and that penalize changes in generation quantities from scheduled levels place wind operators at a relative disadvantage compared to more dispatchable technologies.

These facts mean that wind proponents should pay particular attention to several key aspects of any transmission pricing and scheduling contract or protocol, in particular the following.

- *Take-or-pay provisions.* As described above, contracts that maintain the tradition of requiring a take-or-pay reservation of firm transmission capacity require advance commitments to transmission that are difficult for intermittent technologies.
- *Scheduling flexibility.* Protocols that permit, without penalty, changes in transmission schedules within or near to the active scheduling period provide wind operators with the flexibility they need to make their scheduling commitments to transmission more accurate and minimize those financial risks associated with schedule deviations.

- *Consequences of schedule deviations or delivery imbalances.* Once a schedule is final, protocols can differ with respect to the consequences of delivery deviations and resulting imbalances. Protocols that impose more severe penalties adversely affect wind facilities relative to more dispatchable technologies. Precluding account balancing by use of after-the-fact contracts between different market participants also would disfavor intermittent technologies.
- *Secondary market for transmission.* The ability to buy and sell transmission rights within the active day in a robust secondary market is particularly important for intermittent technologies because such a market will provide additional options for acquiring or disposing of rights in response to changes in the wind resource. The quantity and character of tradable rights also will serve to determine the vitality of the secondary market.
- *Multi-facility scheduling.* The ability to link wind facilities and more dispatchable facilities so that the latter can be scheduled to firm-up the wind resource for transmission purposes is a significant benefit to wind operators, particularly utility operators with significant control of dispatchable resources.
- *Ancillary services.* For intermittent resources such as wind, requirements to make advance purchases of ancillary services (such as spinning reserve) can raise parallel issues to those discussed above regarding advance purchases of transmission rights. Moreover, for similar reasons, wind generators may be at a competitive disadvantage in the market for sale of ancillary services.<sup>10</sup>

In addition to intermittency, the site-specific nature of wind resources also gives wind proponents a unique interest in certain distance and constraint-related transmission scheduling issues. The premise is that wind turbines, being more limited in site/selection than many competing technologies, are less likely to avoid transmission constraints or to locate near major load centers. Thus, as general rule, wind facilities are likely to be more affected by constraints and distance penalties than competing technologies.<sup>11</sup>

This means that wind proponents should be concerned with any aspect of transmission pricing and scheduling that tends to unduly penalize the use of constrained facilities or that takes undue account of the distance from load. Among such issues are the following.

- *Distance-based rates.* Rate terms and conditions that are based almost exclusively on distance from load center or length of contract path need particular scrutiny.
- *Access fees.* Transmission protocols generally permit transmission owners to recover their investment in facilities through some sort of access charge which, depending upon its design, may or may not consider the specific facilities involved or the distance between the generation and load. Protocols such as postage-stamp pricing generally assist remote resources relative to protocols such as contract-path (MW-mile) or subfunctionalized rate methods that tend to promote nonremote resources.
- *Real power losses.* Losses are generally a function of distance and, therefore, are of greater importance to remote resources. Any protocol that results in greater loss charges than are warranted by the distance will discourage wind resource development more than other technologies.

- *Pancaked access fees.* The pancaking of transmission charges for transactions that involve multiple transmitting utilities can unduly penalize remote resources that are seeking to engage in regional transactions.
- *Constraint management.* Since remote generators are more likely to encounter transmission constraints than nonremote technologies, policies regarding allocation of constrained transmission capacity are of special importance to them. For example, protocols that allocate capacity by charging marginal cost-based constraint fees may result in overcollections from those on constrained facilities if the overcollection is later refunded to all transmission users. Such proposals arguably would create a subsidy from those using constrained paths to those using unconstrained paths—a subsidy that would on average penalize wind resources. Additionally, to the extent that utility transmission system practices serve to cause constraints during certain periods, barriers to market participation could be created through elevated charges or curtailments and interruptions.

In addition to the issues arising from intermittency and remote location, wind resources generally also face issues due to their relatively recent introduction into the market. To the extent that constrained transmission capacity is allocated or curtailments made on a first come, first served basis, wind technologies' relatively recent market entry tends to make them a last choice for use.<sup>12</sup>

# ORDER 888 ISSUES

This section discusses the general transmission pricing scheme contained in the open access (OA) tariffs outlined in Order 888's Appendix D. Order 888 contemplates that the OA tariffs will be as similar for all utilities as practicable. Terms and conditions contained in the tariffs may vary on the basis of unique utility operations or requirements that generally are accepted within a specific geographic region and adhered to by the transmission provider. Utilities may propose alternatives to the contract path and embedded cost pricing scheme of the OA tariff. Additionally, new requirements under Order 888 will require transmission customers to secure individual ancillary services<sup>13</sup> that historically have been provided as part of bundled utility transmission service. Wind developers and operators must understand the OA tariff design because it may function as a foundation for transmission services and because it presents significant project cost implications.

At the heart of Order 888 are the concepts of open access and comparability. FERC believes that a unitized tariff design should apply for all wholesale transmission transactions to remove any potential discriminatory power from transmission-owning utilities. The OA tariffs also address the provision and costs for ancillary services related to transmission. An electronic forum will be used as the marketplace where long- and short-run transmission capacity and other services are offered to all. Specific concerns for wind regarding ancillary services and the electronic forum Open Access Same-time Information System (OASIS) are addressed below.

The 888 *pro forma* tariffs contemplate two broad transmission service approaches.

- *Point-to-Point Transmission Services* (PPTS) that support bilateral arrangements between generator and purchaser; and
- *Network Integration Transmission Service* (NITS), whereby the control area of the transmitting utility functions like a pool and NITS transactions are primarily an issue of load balancing.

This discussion focuses on the Point-to-Point Transmission Services (PPTS) because this service is currently the more applicable to most wind projects. Typically, an individual wind project injects power at one location irrespective of any specific demand. As presently designed, Network Integration Transmission Service (NITS) would not serve wind interests well because it is designed to provide transmission to entities that function like utility companies, with designated generation resources feeding the grid and deliveries to a number of diverse loads throughout the grid. In the long run, however, other approaches will develop as experience in open access expands, including the possibility of a hybrid approach.

## Point-to-Point Transmission Service (PPTS)

### The Services

The point-to-point transmission service tariffs are take or pay contracts. They are divided into long-term (one year and longer) and short-term (months, weeks, days, hours) agreements. These agreements are available for firm and nonfirm transmission services. Available services will be noticed on the control area's OASIS. The interactions between available transmission capacity (ATC) and the type and duration of agreements will play an important role for wind project development where power must be transmitted over significant distances and where line capacity may be subject to constraints. Because these contracts are take or pay, the structure of a wind project's transmission arrangements can have a significant cost effect, either in terms of revenue lost for want of transmission, or in terms of expenses related to unused transmission capacity. Additionally, remote projects are likely to trigger costs related to system impact studies and potentially for costs of facility studies and facility upgrades, if required.

Nonfirm PPTS is subject to the system's availability transmission capacity. Simply put, ATC is a function of the total transmission capacity (TTC), less the sum of NITS reservations, plus firm PPTS, plus other contractual obligations. Details of the TTC and ATC calculations appear in another section. ATC may change frequently in response to new firm PPTS contracts or short-run capacity releases on the secondary market. Transmission providers post ATC levels for each significant transmission line segment on the OASIS. All transactions for PPTS (firm and nonfirm) will be posted on the OASIS, and transactions may be facilitated through that system.

Nonfirm PPTS may be available for short periods when those with existing rights do not use their full transmission capacity rights. Availability of this service is potentially sporadic, and may be subject to interruption or curtailment should holders of firm rights need the transmission capacity. Additionally, nonfirm PPTS may be displaced on specific lines where NITS customers choose to inject<sup>14</sup> purchases that cause congestion.

Similarly, firm PPTS is subject to ATC. If a party wishes to enter a two-year firm PPTS contract over path  $AB$  for quantity  $N$ , line  $AB$  must have an ATC greater than or equal to  $N$  for all relevant time periods. Should path  $AB$  suffer from periodic transmission constraints during the peak period, the ATC for that line will reflect this limitation.

The process for requesting firm PPTS allows the transmission provider to review the transaction's effect on ATC and whether it will negatively affect the existing system flow (i.e., constrain some other portion of the system). Should some constraint be anticipated, system impact studies and facility upgrade studies may be required. The customer is responsible for all costs associated with the studies. In the event that a customer commits to a firm capacity reservation in excess of that immediately available and commits to upgrade costs (or costs associated with an alternative means of alleviating the constraint such as changed network generation dispatch), the portion of transmission capacity immediately available will be released to the customer. The remaining increment will be made available only when the entire upgrade project is completed.

### The Secondary Market

Order 888 and the OA tariffs specifically contemplate creation of a secondary transmission market made possible by the release of firm capacity reservations by sale or assignment. The initial transmission customer (i.e., the reselling customer) remains liable to the transmission provider for costs associated with any capacity reservation not put into use. All finalized secondary market

transactions will be posted on OASIS. Service to the new customer will occur after proper notice to the transmission provider. An understanding of the secondary market is essential for wind projects in order to minimize financial exposure related to “stranded” transmission capacity under the take or pay OA tariffs.

Pricing for the secondary market is capped at the higher of 1) the original rate paid by the reseller; 2) the maximum rate allowed under the tariff at the time of the transaction; or 3) the reseller’s opportunity cost. Changes in service terms generally will be treated as a request for new service, although it is possible to change the original set of injection points under firm PPTS to nonfirm service at a secondary set of points.

### **Transmission Pricing Issues Related To Order 888**

Several potential issues are of concern to wind generators related to the transmission charges imposed by a utility’s OA tariff. These include the take or pay nature of the tariff, pancaking of fees across multiple line segments,<sup>15</sup> penalties for deviations from delivery schedules and the potential exposure of nonfirm customers to interruptions based on system constraint management. The OA issues will vary by utility ratemaking schemes.<sup>16</sup> General concerns focus on potential discriminatory effects on remote resources such as wind, and the potential for overcollection due to the rate design employed.<sup>17</sup> Overcollections are a concern because of unintended inequities in the manner that funds are collected. For example, remote wind projects may contribute more in the aggregate to the overcollection because of contracting services over multiple line segments (under contract-path pricing), yet they may not recover in proportion to their contribution because the refunds are based on the volume wheeled.

An alternative to contract path pricing based on discrete line segments is the so-called postage stamp pricing. This is a single, unitized charge that has a smaller potential to discriminate on the basis of distance. This type of fee is similar to a system access fee proposed as part of the California ISO/PX proposal discussed below. The basis for this rate should be the marginal cost of the service, although embedded cost (based on historical throughput) also could be used. Embedded costs present a potential for overcollection if a certain amount of system usage was assumed that is significantly below the actual usage. This could occur because of the historic overbuilding of transmission facilities and because the latent capacity of lines will not be discovered until detailed system impact studies are conducted.

Another potential rate design approach would use the contract path along with a “subfunctionalized” cost structure that imposes fees according to the value of assets utilized along the path. The potential for overcollection exists here because of the fiction of contract-path or because the rates are based on a usage assumption that does not reflect actual usage.

Where the transmission customer must secure capacity from a number of providers, or where the customer purchases all ancillary services from the system operator, there is a potential for the pancaking of rates. At issue here is the overcollection of funds beyond those required to make the provider whole. This is also a matter of ratemaking methodology. An embedded cost basis could result in overcollections due, for example, to the improper allocation of costs across different services (i.e., a greater proportion of costs are allocated to the services in highest demand). Marginal cost based rates could alleviate this problem where aggregated customer actual usage determines the fees. As stated earlier, this issue is important because pancaking can result in a significant market barrier for remote wind resource where the power must cross a number of control areas.

Real power losses occur whenever power is transmitted. Under the PPTS tariff, the customer is responsible for replacing losses. This could be achieved by injecting sufficient amounts of energy and capacity to make up for losses incurred during the course of transmission. Alternatively, the shortfall could be purchased from some other entity (including the transmission provider if it offers this service). No real power losses ancillary service exists under the OA tariff. Wind projects may be able to structure the PPTS agreement so that the ultimate deliveries reflect cumulative system losses.<sup>18</sup> If the control area operator requires that losses be replaced by paying some fee, a project may have to pay more than its cost of generation. This would be a clear disadvantage to remote projects such as wind. Given the natural variability in output from wind projects, it is not clear whether structuring the PPTS agreement to cover losses by reducing the delivery point reservation is practicable. Another complication is that losses on any system pose a dynamic problem unique to each transmission system. Although some forecasting of losses is possible (via the power loss factors posted on OASIS), the exact amount of losses will vary over time, especially when a number of line segments are involved.

### **Discussion**

The wind industry must recognize that securing transmission services will require finding a suitable balance between firm and nonfirm PPTS service reservations, along with a potentially high degree of participation in the secondary transmission market. Issues faced by developers will pivot on the correlation between wind generation and transmission line loading profiles on individual line segments. When a line required to move power from wind generation to the ultimate point of delivery faces potential constraints during periods of wind generation, firm services may be indicated for a large portion of that generation potential. Otherwise, the wind operator could face a situation where it can deliver a larger amount of power than its current capacity reservation allows. If the line is constrained only periodically, the project may be able to secure the additional transmission capacity from the nonfirm portion of the market.

Although the secondary market may serve to remove certain financial risks associated with firm capacity reservations under the take or pay design, this option is driven primarily by demand for transmission capacity. If the project is located in a remote area and other generation assets located on that line are not subject to the same resource intermittence, then the secondary market could be workable. This option is a function of which line segments are reserved on a firm basis over the contract path and the demand to move power over those lines.

Assuming that a project will be wheeling through multiple service areas, the developer will be responsible for securing transmission across all areas. This will require an understanding of each system and the individual line segments involved in the ultimate transaction. Although Order 888 directs the transmission provider to assist the customer in developing its integrated transmission plan, it would be prudent for the developer to know these systems in advance. This understanding could affect site selection and financing if, for example, several system impact and facility studies were required for those line segments that must be secured.

# OPEN ACCESS SAME-TIME INFORMATION SYSTEM (OASIS)

Access to transmission system and services information will be an important aspect for wind projects that seeking to minimize their transmission service expenses. The open access same-time information system (OASIS) has been created to help create a workable open access transmission market as contemplated under Order 888.<sup>19</sup> FERC has ordered that OASIS be fully operational by January 3, 1997. With OASIS, both utility and nonutility wholesale market participants (sellers, resellers, purchasers and others seeking market information) have access to a single information source regarding the transmission and ancillary services market. This single source of information, combined with the open access tariffs, forms the backbone of the competitive transmission services market. OASIS is of concern to the wind industry because it is the common means of inquiring about and requesting transmission services. It also will serve as the marketplace for secondary transmission capacity. In essence, OASIS is the clearinghouse for all transmission-related services.

OASIS applies both to the local control area information system (an OASIS node), and the broader interarea information system network outlined by FERC. Utilities that provide transmission services will create (or contract out) their OASIS node responsibilities, and other entities may repackage information posted on OASIS.<sup>20</sup> The system is accessible via the internet's world-wide-web (WWW) with standard web browser software. Costs associated with development of the system generally will be rolled into wholesale transmission rates; however, some costs associated with ancillary service transactions (primarily any services beyond those mandated by Order 888) may incur additional fees.

Because of their generally remote location, wind resources should be particularly concerned that OASIS systems will enable generators to easily obtain information about multiple systems for regional transactions. To the extent OASIS systems use consistent methods and presentation schemes, it will be much easier to match up the transmission segments necessary for such regional sales. Conversely, if OASIS systems use inconsistent methods (e.g., an ATC number on one system is calculated very differently from the next), then it will be very difficult to match up transmission across multiple systems. The current trend indicates that OASIS nodes will reflect the transmission system of certain regions, possibly on a RTG basis, thereby reducing concerns about inconsistencies.

Standards apply for the presentation and exchange of information between a node and customer. FERC anticipates that the standards will change over time as experience is gained and information

technologies develop. A potential exists for inconsistent cross-nodal graphical information presentation, but it is partially alleviated by standardized formats (templates) used to upload or download data or to make queries to OASIS.<sup>21</sup>

Wind projects should anticipate developing internal computer systems to communicate with OASIS so that nonfirm PPTS can be quickly secured and to post capacity they choose to resell.

One potential cross-node consistency issue may lie with how the information presented by an OASIS node is generated. The underlying question is whether there is comparability between the terms and analysis used for determining transmission service availability. Order 889 contemplates that ATC will be calculated on a similar basis across nodes and will be updated within minutes of any change driven by new or terminated transactions, service interruptions or curtailments.<sup>22</sup> Wind projects that must send power across a number of nodes must be familiar with the conditions of the PPTS service and the way in which ATC is calculated within each OASIS node along the contract path. Because each node will post (or make available on request) background information, variations in ATC treatment can be determined. A better solution, however, would be to have ATC determined in a consistent fashion throughout the region or the nation. To that end, wind proponents should support current efforts to standardize ATC calculations in the Western Interconnection.<sup>23</sup>

As noted in the overview, the presence of a robust secondary market in transmission rights is important for intermittent resources. Order 889 requires that participants in the secondary market for transmission services and capacity have the same access to OASIS pages as primary providers. Information regarding the offerings of secondary transmission providers (resellers) will be posted at the OASIS node where the capacity initially was secured. The requirement ensures that all transmission services information related to a specific pathway is available at one location and is presented in a nondiscriminatory manner. This is important to wind projects that seek to make capacity available at those times when they have no power to wheel.

# ANCILLARY SERVICES

The OA tariffs also address so-called ancillary services. These services are those that the integrated utility historically provided for system reliability purposes when transmitting power. Because Order 888 requires functional unbundling, transmission customers are required to purchase these services as a condition of transmission access. Certain services—such as scheduling, system control and dispatch—must be provided by the transmission provider.<sup>24</sup> Other services, such as spinning reserves, may be secured from other entities or through self-provision. The OA tariffs require that the customer specify the sources of ancillary services.<sup>25</sup> Specifics of the required services are generally delineated by the historic operation of the control area; this may be dictated by regional transmission standards (e.g., WSCC, NERC, etc.) or “good utility practices.” Future development of the ancillary services market may occur as additional services are unbundled from FERC’s six categories of ancillary services, or as market participants find demand for other services. Because ancillary services are secured for system reliability purposes, it can be assumed that reliance on those services outside some contingency situation will trigger penalty fees.<sup>26</sup> Finally, it is possible that ancillary services providers could repackage services to meet specific customer needs.<sup>27</sup> This will be permissible as long as Order 888’s goals of non-discriminatory access and comparability are maintained.

FERC’s six categories of ancillary services are as follows:

- **Scheduling, System Control and Dispatch Service**  
*This service must be purchased from the transmission provider.* Fees are based on the capacity reserved, with a provision to ratchet up the charge if the services are used above the contract reservation quantity. This service does not appear to impose undue costs on wind generation.
- **Reactive Supply and Voltage Control from Generation Sources Service**  
*This service must be purchased from the transmission provider.* Fees are also based on the capacity reservation, with a ratchet provision to increase the charge if the service is used beyond that reservation. The OA tariffs could be read to impose case-by-case analysis of each transaction’s requirements.<sup>28</sup> Treatment may vary by transmission provider. However, traditional embedded-cost ratemaking is the most likely basis for rate design. To the degree wind facilities supply reactive power and voltage support, their contribution should be reflected in the obligation to secure this service.
- **Regulation and Frequency Response Service**  
*Transmission customers must secure or self-provide and the transmission provider must offer the service when the PPTS is used to serve load within its control area.* Because wind resources do not operate as dispatchable units under automatic generation control (AGC), wind

projects may need to secure greater degrees of this service. Power conditioning equipment may serve to alleviate a portion of this requirement. An outstanding issue is related to the measurement of reactive power and voltage control impacts associated with individual transactions. Should power conditioning equipment provide reactive power and voltage support, it is likely that the transmission provider will require some showing that the equipment will reliably maintain the required 60 Hz at the point of interconnection.

- **Energy Imbalance Service**

*Transmission customers must secure or self-provide and the transmission provider must offer the service when the PPTS is used to serve load within its control area.* This service is offered to correct mismatches between scheduled deliveries and loads on an hourly basis. The service operates with a plus or minus 1.5 percent deadband with substantial penalties for under deliveries during peak periods. There is a 30-day rolling window for correct of imbalances. Failure to correct will trigger additional charges for the cost of energy provided (e.g., average incremental price of energy during that period). Because wind generation output is difficult to schedule accurately, there is a potential for significant energy imbalance fees, especially where the deadband level is exceeded. It is possible that intermittent generation like wind could be tied with another generation source to cover possible imbalances at any hour in real time, or the imbalance potentially could be corrected through after-the-fact contracts with other market participants.

- **Operating Reserve-Spinning Reserve Service**

*Transmission customers must secure or self-provide and the transmission provider must offer the service when the PPTS is used to serve load within its control area.* As noted earlier, it is not clear whether wind resources should be treated the same as conventional generation sources in terms of required spinning reserves. It could be argued that this resource presents a lower risk of a fuel or generator-related failure, which takes the entire plant capacity off-line instantaneously.<sup>29</sup> Additionally, wind contributions to system supply sometimes are viewed as a reduction in system load with a related reduction in demand for conventional generation output. These concepts could be used to argue that wind generation should not face the same reserves requirements.

- **Operating Reserve-Supplemental Reserve Service**

*Transmission customers must secure or self-provide and the transmission provider must offer the service when the PPTS is used to serve load within its control area.* As noted above, because wind is not a dispatchable resource and is subject to production variations, it should not be obligated to secure as high a level of reserves. This argument assumes that the load served by wind could be curtailed, or that some other generation resource would be tied to wind generation to firm up deliveries. While some spinning reserves may be necessary to address the immediate loss of wind generation (due to rapid resource drop off or some transient event), supplemental reserves requirements should be reduced in recognition of the intermittent nature of the resource.

# THE CAPACITY RESERVATION TARIFF NOTICE OF PROPOSED RULEMAKING

At the same time FERC issued orders 888 and 889, it released a new Notice of Proposed Rulemaking (NOPR) *Capacity Reservation Open Access Transmission Tariffs*.<sup>30</sup> The CRT proceeding is in its early stages, with the initial round of comments concluded. A detailed examination of the NOPR's ramifications for the wind industry should occur after these comments are reviewed. However, we can discuss some clear effects on wind generation, especially those projects that are owned by investor-owned utilities (IOUs).

As discussed above, Order 888 creates two tariff schemes: point-to-point transmission services (PPTS) and network integration transmission services (NITS). The CRT notice asks this fundamental question: Should these distinct services be combined into a single transmission capacity reservation system? The NOPR proposes that utilities explicitly reserve capacity for sales to native load, which they currently withhold from ATC without economic consequence.<sup>31</sup>

For nonutility generation (NUG) projects no distinction is made between the CRT approach and PPTS. In either case project operators must assess their need for transmission services and select some set of services that is appropriate for their needs. Whatever the ultimate balance selected, the project has a reasonably fixed financial liability associated with the take/or/pay reservations.

However, the CRT proposal will trigger a new approach for utility-owned wind projects that are receiving transmission under the utility's implicit reservation for native load. Under Order 888, a utility need only make an explicit reservation of capacity on its own system for off-system sales; transmission used by the transmission-owning utility for its native load is implicitly reserved by virtue of being deemed "not available" for other uses, but it is not "reserved" in the sense that transmission must be reserved by other users. The CRT notice would change that by requiring the utility to explicitly reserve transmission for all its uses, both off-system sales and native load service.

For wind facilities owned by transmission-owning utilities, this reservation requirement may require commitments that are inconsistent with the intermittent nature of the resource (as discussed above with regard to other wind owners' reservations of transmission).

The CRT notice would also trigger new requirements for municipal utilities, with wind resources obtaining transmission under the NITS pursuant to Order 888. NITS allows the utility to serve disbursed native load from a number of generation facilities as it has historically. Under NITS, wind generation's natural intermittence is not a significant issue as long as other interconnected

generation can step in and meet demand. Wind projects simply are integrated into the system's supply profile; when wind production tapers down, other resources ramp up. Additionally, under the NITS pricing scheme, *the customer pays according to usage*, not the fixed amount set by an elected reservation as in the take/or/pay PPTS. Therefore, under NITS, the utility's transmission expense that can be assigned to wind generation is lower than it would be under a reservation-based approach.

The Order 888 approach has NITS requirements netted out from the TTC to determine the PPTS ATC. This simply means that the quantity of transmission potentially available to firm PPTS is the surplus portion beyond that is required to serve the IOU native loads. Of course, in the very short run, unused capacity is made available as part of the nonfirm ATC. Should NITS and PPTS be combined under the CRT, all generators, including IOU and NUG wind projects, will go to the market for their transmission requirements. Under the combined program, therefore, the ease of IOU wind project integration will be lost, and those resources (and all resources) will be required to take service under the PPTS design.<sup>32</sup>

Benefits of this proposal includes a greater degree of administrative simplicity and the potential expansion of the secondary services market. Because the combined CRT program is reservation-based like PPTS, FERC believes that ATC will be easier to determine and the disparities in transmission expenses under the dual system will be eliminated. Under the CRT system, all customers will be treated equally. FERC also believes that the transmission system may be more efficiently used because all participants will have similar incentives to avoid unnecessary take/or/pay expenses (i.e., a level playing field in terms of risk exposure). FERC suggests that the single system may give better pricing signals for transmission system upgrades and provide a means of developing new transmission products.

Finally, apart from its specific proposed scheme, the CRT notice presents the wind industry with an important opportunity to present creative proposals to the FERC about transmission acquisition by intermittent technologies. In particular, the industry should consider proposing that the FERC mandate a special capacity reservation tariff for intermittent technologies. This tariff could, for example, propose that intermittent technologies be permitted to reserve transmission on a pay for what you use basis, rather than on a take or pay basis. Under such a tariff, intermittent technologies could pay no or a nominal access charge, allowing them to reserve a maximum capacity usage right, within which they only pay the full fees for the portion actually used. At least for unconstrained paths, this proposal appears to be an appropriate and practical solution—that does not impair competing interest—to the intermittency problem.

Competing users in constrained paths will object that such a system allows discriminatory access and uneconomic use of the limited capacity. They will argue that the allocation of the limited capacity must be more rigid so that market signals give the proper incentives for efficient use of the limited resource. In particular, they will argue that, on constrained paths, such a proposal threatens to have capacity remain unused even during curtailments because there will be no practical opportunity to reallocated capacity that is not used within each hour. To address these concerns, the wind industry could either limit its proposal to unconstrained paths or, alternatively, develop alternative capacity release protocols that would make the unused wind capacity available to dispatchable technologies. In essence, the latter might link a wind resource to a dispatchable technology for transmission purposes, while still permitting the wind resource to be fully used.<sup>33</sup>

# RETAIL WHEELING, FLOW-BASED PRICING SCHEMES AND ISO/PX FORMATION

California and several other states currently are considering restructuring proposals that would place transmission system operation in the hands of an independent system operator (ISO), create a power exchange (PX) for bidding resources and loads, permit direct access (i.e., retail wheeling) and make fundamental changes in the pricing of transmission and ancillary services based on flow-based zonal or nodal models. Although a comprehensive review of such proposals is both too California-specific and beyond the scope of this paper, a review of wind issues would be incomplete without at least a brief overview at the major issues presented by such schemes.<sup>34</sup>

In some respects, the California-type structure offers interesting benefits for the wind industry. The first is that the proposal contains no penalties for deviations in real-time from forecasted or bid generation levels. Under the proposal, any resource that generates more or less energy than scheduled through the ISO is simply considered to have sold or purchased energy at the real-time marginal spot price. This means that a wind generator can deviate from schedules without any penalty other than the difference in the spot price and bid price.

Moreover, for wind projects, this scheme also can obviate the need for bidding, scheduling or arranging transmission at all-at least on unconstrained lines. The reason is that projects that run without bidding or acquiring generation are simply considered to have overgenerated against a schedule of zero and therefore are paid the real-time spot price for the energy delivered. It must be emphasized that the spot price may be quite low relative to the total “all-in” cost of wind generation, a problem that must be addressed through credits, portfolio standards or other mechanisms to assist the wind industry. However, relative to the incremental operation costs only, which are negligible for wind, the spot price should be sufficient in almost all circumstances to make it economic for wind generators to operate as compared with sitting idle. Given this fact, and making the important assumption that capital costs can be recovered through a combination of energy prices and other revenue sources, the California scheme provides the wind generator with a variety of options to deal with intermittency that are unavailable in other regimes.<sup>35</sup>

Another advantage of the California scheme that contributes to the above result is that the access fee, which is intended to recover the embedded cost of the transmission system, is paid by end-use customers based on their location, irrespective of generation. Generators pay no access charge. Again, this enables operation without prior bidding or transmission procurement based on real-time output, for facilities with operation costs that are low enough to be recovered in typical spot prices.

For congested transmission paths, the foregoing opportunity is less clear. The California proposal would charge generators a “congestion” fee for dispatch on congested lines based upon the difference in marginal spot prices between points on either side of the congestion. This congestion fee can make it uneconomic for wind facilities to operate and thereby nullify the advantages discussed above. This fee also may adversely affect wind projects simply because of wind is more subject to constraint fees due to remote locations.

# TRANSMISSION PLANNING ISSUES

For long-term wind resource development, transmission system upgrades are necessary to promote access to key undeveloped wind resource areas. Such is particularly the case for large-scale development of wind resources in areas (such as Montana and other inter-mountain region states) where wind resources exist at great distances from major load centers. Accordingly, wind proponents have a particular interest in the transmission planning process.

Historically, transmission system planning has been conducted by individual transmission-owning utilities subject only to the regulatory oversight of their state utility commission or other state energy authority. The only organized regional coordination of transmission system planning has been through regional reliability councils (such as the Western Systems Coordinating Council). This coordination, however, has been limited to ensuring regional system reliability and stability. Thus, for example, a utility planning a major transmission line would review its plans with the reliability council members to obtain a capacity rating for operating the new facility in a manner that would not adversely affect neighboring interconnected systems. However, issues such as the need for the facility, the relationship of the facility to integrated resource planning and cost-minimization have been left to the discretion of the individual utilities and their state regulatory authorities.

With the passage of the National Energy Policy Act of 1992 (EPACT) and the creation of voluntary regional transmission groups (RTGs), however, the FERC has begun to promote regional transmission planning. Specifically, the FERC has conditioned approval of RTGs on the development of regional transmission plans. These plans seek to harmonize the planning efforts of individual utilities and states on a regional basis. It should be emphasized, however, that this planning process remains essentially voluntary. No utility can be compelled to join an RTG and, even for those who join, the plan cannot compel or prohibit construction of any specific facility. The effect of the nonmandatory plan, therefore, lies largely in its moral force, i.e., its ability to influence utilities as well as the siting and ratemaking decisions for projects they choose to propose.

FERC has approved three RTGs, all of which are in the West: the Western Regional Transmission Association (WRTA), the Southwestern Regional Transmission Association (SWRTA) and the Northwest Regional Transmission Association (NWRTA). WRTA functions as a western umbrella RTG with overlapping (though not identical) geography and membership relative to the other two RTGs. Thus, for planning purposes, coordination issues exist regarding the plans being developed by all three RTGs.

Further complicating the picture further is a significant effort by the WSCC to expand the scope of its transmission planning process to include issues other than reliability. Again, however, the

WSCC does not have authority to reject or compel any specific action by a utility for reasons other than reliability.

The efforts of the three RTGs plus the WSCC in the West have significant potential for conflict and duplication. Ironically, such potential threatens the regional planning that the FERC and all four planning bodies desire to promote. This danger is somewhat mitigated by the overlapping membership of the organizations (many of the same people are involved and, therefore, communication between the organizations is good, at least among utility members). Provisions of the WRTA governing agreement that even require consideration of merging with the WSCC in the near future, although approval of all segments of the industry would be required. Additionally, the potential for conflict among the various transmission planning efforts has been partially mitigated by development of the Western Interconnection Coordination Forum. This group, comprised primarily of RTG executives, should coordinate the development of certain elements common to the RTGs. Although this recent development is encouraging, it does not completely eliminate concerns about conflict and duplication, particularly as the groups begin to confront difficult or contentious issues.

From the perspective of wind development, the efforts to promote regional planning are a positive development and should be encouraged. However, these efforts address only one of the core planning issues affecting wind. That issue is coordinating planning so that a facility that is uneconomic for any individual utility, but that is economic for several acting in concert, can be identified. Thus, for example, a utility that would like to promote a wind project which requires transmission upgrades that cannot be justified for the intermittent resource alone, may more easily find a partner interested in the upgrade through the RTG/WSCC coordinated planning process.

Several other core planning issues affecting wind exist that the present process is ill-suited to address, among which are the following.

- *Coordination with IRP and consideration of diversity and environmental benefits in transmission planning.* The interdependence of generation and transmission means that transmission planning must be closely coordinated with generation planning. This interdependence creates a classic “chicken-and-egg” problem, wherein wind resources can be excluded from generation plans for lack of adequate transmission, while the necessary transmission is not built for lack of generation. At present, transmission planning is based upon the public plans of utilities and other power producers for construction of new facilities. To the extent these generation plans reflect integrated resource planning or other public policies for diversity and environmental values, these factors are indirectly considered in transmission planning. However, there is no direct consideration of these factors in transmission planning.
- *The effect of competitive markets on planning.* Utilities that are facing even greater competitive pressures are increasingly reluctant to make transmission or any other expenditure that either assists their competitors or increases their relative costs. Thus, the willingness of utilities to plan transmission for wind resources is adversely affected by the restructuring of the industry. Moreover, due to competitive pressures, utilities and other market participants may be more reluctant to share their generation plans with transmission planners. These factors make progress toward regional transmission planning more difficult.
- *The impact of restructuring on planning.* Proposals to create ISO’s, functionally unbundle utilities, alter transmission pricing or make other fundamental changes in the operation of transmission facilities create great uncertainty for transmission planners. Such uncertainty, in

turn, increases risk and decreases the likelihood that new transmission facilities will be built until the new market emerges.

Overall, at least in the near future, major transmission upgrades will be difficult to plan, finance and construct until market structures, regulation and pricing stabilize. This will be a barrier to some new wind development opportunities that require or would benefit from upgrades. At the same time, there is some possibility that restructuring will result in more efficient use of the regional grid, thereby creating latent transmission capacity increases.

Nevertheless, certain universal truths will not change. For the transmission upgrades necessary for wind development to move forward in this environment, there must be clear and near-term economic benefits so that participants are willing to bear the costs. Particularly in this time of uncertainty, upgrades will not be built on speculation. This means that transmission upgrades will continue to fall into two historic categories: 1) upgrades linked to specific generation additions; and 2) upgrades to relieve present congestion that is causing opportunity or congestion costs high enough to pay back the upgrade investment quickly. Due to its intermittency and capacity factor, it is difficult to justify major transmission upgrades needed solely to enable wind resource development. Thus, even specific commitments to the addition of wind generation are not likely to cause necessary transmission upgrades without linkage to other, dispatchable generation that enables full use of the new capacity.

## CONCLUSION

The intent of this paper has been to make a preliminary assessment of system operation and transmission-related issues of particular interest to wind project operators and developers. There are, of course, several issues that remain to be addressed at the federal, state and regional levels regarding restructuring. This paper may serve as a catalyst for further policy discussion and development in these arenas with recognition of wind's unique and valuable characteristics.

Research for this paper suggests that certain issues warrant additional review. These suggestions are offered because the issues may pose potential barriers of significance to wind projects, or because unique opportunities exist to develop policies that embrace those characteristics that are unique to the wind resource. The suggested issues for additional review are, in order of relative priority:

- Whether bidding protocols present opportunities to participate in the market that are consistent with the characteristics of the wind resource.
- Whether, and to what extent, the pancaking of access fees presents a significant market barrier.
- Whether, and to what extent, ancillary services requirements for wind generation should reflect unique resource characteristics, and how to ensure that those requirements are applied correctly and without prejudice.
- A tariff proposal for presentation at the FERC CRT notice as discussed in Section VII above (pay for what you use).
- How, and to what degree, the creation of a secondary market in transmission will develop and in what niche wind projects will find themselves.

# NOTES

1. Electric Power Research Institute. *Planning Your First Wind Power Project: A Primer for Utilities*, no. TR-104339 (Palo Alto, Calif., December 1994).
2. Electric Power Research Institute. *Perspectives on Wind Plant Capacity Accreditation*, no. TR-104339 (Palo Alto, Calif., September 1994).
3. Electric Power Research Institute. *Planning Your First Wind Power Project*.
4. Electric Power Research Institute. *Perspectives on Wind Plant Capacity Accreditation*.
5. Many utilities have invested significant amount of money in the demand-side management resource. Where the utility systematically sheds load during system peak periods as part of its demand-side management measures, this flattening of the system's demand curve can be conceptually approached as if it were another generation resource. Some DSM measures can be taken when needed—such as load shedding during system peaks via interruptible customers or other non-firm customers—and, therefore, the gradual loss of an intermittent resource over the next hour may not be as critical to serving the reduced load. This is not to assert that service reliability should or needs to be compromised to integrate wind resources. But given the changes developing in the industry, it is reasonable to argue that certain demand-side measures (or other generation resources such as hydro) could be matched to firm up an intermittent resource for the short-term as the resource availability tapers off. This effect depends on the degree of wind penetration (i.e., percentage of system generation), the ramping characteristic of individual wind generation facilities or locations, and the system's ability to manipulate load or dispatch other fast-ramping generation resources, either through direct control or via contract.
6. California Energy Commission. *Renewables Working Group to the CPUC*, no. 500-96-008 (Sacramento, Calif., August 1996).
7. Pacific Northwest Laboratory. *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*. no. PNL-7789 (Richland, Wash., August 1991).
8. The take-or-pay rate has been the most common approved by regulators. It allows for recovery of transmission capital costs relative to a party's capacity reservations, or the owner's opportunity costs, or some other economic rationale. Generally speaking, this rate design is approved by regulators as an equitable way of recovering capital costs. Other rate design approaches have been used to recover similar fixed capital costs.

9. Reservation refers to the volume of contracted transmission service over some time period, e.g., kilowatts (kW) per hour or kilowatts (kW) per month, etc. This quantity may differ from the actual volume scheduled with the control area operator at any given hour of the day. Quantities reserved may reflect the customer's strategic decision to gain rights to transmission services over a period of time, especially where capacity constraints are anticipated. The scheduled quantity is a reflection of the customer's actual demand for services for each hour of each day. When customers fail to schedule deliveries at volumes equal to that reserved, the unused capacity may or may not be available for other customers' periodic use.

10. That is, intermittent resources will not be able to provide ancillary services in a manner similar to fully dispatchable generation resources.

11. This generalization is not true for all wind facilities or developers. Moreover, the generalization also depends upon where the principal competition facing the wind resource is located—a consideration that can be subjective. For example, existing wind resources seeking to sell within their state may face fewer constraints and be located closer to loads than competition coming from outside the state. Conversely, these same facilities may be in the opposite posture relative to competition from, for example, gas-fired projects located within the state. With this important caveat, wind resources generally will face more transmission constraints and be located further from loads than their competition.

12. For utility-owned wind facilities, this may not be as true because the utility may be able to use longstanding transmission rights that predate the particular generation.

13. The term ancillary services refers to a set of services related to transmission. These services are concerned with system operation and reliability issues such as the scheduling of deliveries, voltage support and backing up a generation source. Details are discussed in a separate section below.

14. Economy power: generally non-firm energy purchases made from system where the purchase price would be below the purchaser's marginal cost of generation. One typical example would be purchases of hydroelectric power generated by fish flows or releases made to increase storage availability. Absent the purchase, the energy would often be lost.

15. The historic conceptual model for these agreements, referred to as the contract-path, is primarily used for transactional convenience. The laws of physics dictate the actual flow of electrons; actual physical flow can potentially move in directions very different than the direction indicated in the contract. Although the alternative of flow-based contracts can be contemplated, currently applied grid control technology is not sufficient to foster this type of contracting. (See Order 888, pp. 92-98.)

16. Order 888 outlines a standardized ratemaking scheme based on contract path and embedded cost pricing. The order also stresses that alternatives can be used and that the utilities are free to propose alternative methods. For example, flow-based, real-time pricing could be implemented using a remote metering network or the utility could use incremental or opportunity costs. Any proposal is subject to FERC approval, and must maintain the nondiscriminatory access and comparability goals of 888.

17. Potential discriminatory impacts are unintended effects from a rate design upon a class of customers. This is not to imply that any specific rate design is promoted with the intent to discriminate. Regulatory review should examine various rate designs to ensure that no customer class regularly receives economic signals more favorable than some other customer class.

18. Order 888 appears to authorize this approach; however, the language in the OA tariff indicates that losses must be replaced. See OA tariff, § 15.7.

19. OASIS is a concept similar to the electronic bulletin boards (EBBs) created by FERC for capacity releases and transmission services in the natural gas industry. FERC's Final Rule (Order 889) codifies OASIS at 18 CFR §37.75 FERC paragraph 61,078 (April 24, 1996). Along with Order 889, FERC issued the initial Standards and Communications Protocols for OASIS Standards and Protocols. By an order dated September 10, 1996, FERC released an update of the OASIS Standards and Protocols. Periodic updates will occur over time. The latest Standards version can be downloaded via <http://www.tsin.com>.

20. Order 889 creates an information market by allowing other entities to repack the transmission information. Telecommunications, software and data processing companies are creating turnkey information systems to comply with OASIS requirements. Additionally, waiver provisions apply to small IOUs and IOUs that participate in a larger node. Nonpublic utility transmission owners (e.g., municipal utilities) may seek exemptions or choose to participate voluntarily in OASIS nodes under the auspices of the Order 888 reciprocity provisions.

21. FERC allows varying formats for information display because this is anticipated to be the interface for more casual transactions. The two standardized mechanisms called for in the Standards and Protocols address the needs of parties involved in numerous transactions (e.g., short-term capacity releases). Standardization is accomplished through the use of templates dictated by FERC, with common variable names and formats. One approach is the ASCII delimited file with header information that indicates which template applies. The second approach uses WWW URLs (universal resource locators) that point to standardized datasets residing on another computer (either the transmission system information provider's or potential customer's).

22. ATC and TTC apply to point-to-point service under the open access tariffs. No TTC or ATC will be calculated for network services because that service is too dynamic.

23. This is an ad hoc effort involving representatives of the various Regional Transmission Groups and the Western Systems Coordinating Council. For information, contact Dean Perry of the Bonneville Power Administration, (503) 230-4009.

24. This assumes that the transmission provider is also the control area operator (CAO). If the CAO is a different entity, then the customer may transact directly with the CAO. Otherwise, the customer will transact with the transmission provider that passes through the CAO's charges for the mandatory services.

25. The OA tariffs are unclear as to when and how often ancillary service providers may be changed. Presumably this would be a negotiated term to a PPTS agreement. Where the transmission customer secures ancillary services from a competitive market, disclosure of the service provider prior to actual scheduling implicates sensitive trade information.

26. Penalty fees could be the OA tariff provisions that charge for usage above capacity reservation, or similar mechanisms, such as the scheduled delivery deviation deadbands, which also trigger elevated charges according to the severity of the deviation. While the initial service fee is cost-based, the elevated charges appear designed for their deterrent effect rather than for pure cost recovery purposes.

27. The FERC is encouraging new transmission products through the bundling of services useful needed by customers. See Order 888, pg. 206.

28. See Order 888, pg. 209-211, for a discussion of this service. Order 888 indicates that to the degree customers are able to reduce requirements their obligation should be reduced. This may be reflected in the degree to which a generator can provide localized voltage stability. If wind facilities are able to assist in voltage support in remote locations, their obligation should be reduced accordingly.

29. Although a single wind turbine may present the same risk of failure as a fossil facility, the argument is that the risk to the entire system is mitigated by the aggregation of all turbines within a single facility, and also by the aggregation of all facilities within a given control area. Therefore, this argument would suggest that the magnitude of reserves required for a wind facility should be reduced accordingly. However, while the wind facility may not face the same risk of transient outage, a counter argument is that remote resources such as wind face a higher risk of interconnection failure because they are further from the load center. Therefore, the need for reserves does not change because the load still must be served when that outage occurs.

30. Capacity Reservation Open Access Transmission Tariffs, Docket No. RM96-11-000, Notice of Proposed Rulemaking, April 24, 1996. The NOPR proposes an effective date of December 31, 1997.

31. Because the native load reservation is excluded from ATC calculations, the utility does not hold a true right to the capacity, so the reservation is effectively excluded from the secondary market. The CRT proposal would eliminate this anomaly.

32. The NOPR suggests PPTS as the model tariff. Other models and pricing designs, including a hybrid design that calls for reservations across constrained transmission interfaces similar to the PPTS design have been suggested, and service in unconstrained areas under a unitized fee similar to NITS. However, the premise of FERC's CRT proposal remains the same: one tariff applies to all transmission customers.

33. This latter idea will not, of course, remove entirely the argument that the proposal creates a preference for the intermittent technology which is discriminatory and uneconomic. Implicit in the proposal is an allocation of constrained capacity that gives a preference to use or lose intermittent technologies over others that may have lower apparent costs. That is the policy choice the proposal would force the FERC to confront.

34. Note that FERC approved this ISO/PX structure in concept. See Order Conditionally Authorizing Establishment of an Independent System Operator and Power Exchange, Conditionally Authorizing Transfer of Facilities to an Independent System Operator, and Providing Guidance. 77 FERC ¶ 61,204. November 26, 1996.

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35. It is important to remember that choosing not to bid into the PX and supplying power in any event will yield the market clearing price for that hour. This price could be zero or near zero, especially during periods of low demand and high generation.

## GLOSSARY

**Ancillary services**—Those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission provider’s transmission system.

**Bundled utility transmission service**—Includes both transmission service and those services necessary to support the transmission of energy from resources to loads while maintaining reliable operation of the transmission provider’s transmission system.

**Capped**—Upper limit.

**Commodity price**—The generation-only for a unit of electricity, not including any transmission or ancillary service costs.

**Comparability**—The requirement that public utilities owning and/or controlling facilities used for the transmission of energy in interstate commerce provide third-party access to such facilities under the same terms and conditions that the public utility takes service for its own wholesale sales and purchases.

**Constraint fees**—Fees charged for the purpose of recovering congestion costs or to provide a market mechanism to clear transmission.

**Contract path**—The specific transmission facilities identified in the contract to be used to deliver energy to a buyer from the seller.

**Deadband**—A narrow range about a setting within which no action is taken.

**Distributed resources**—Typically smaller sized generation resources located on the distribution and/or transmission system close to selected loads and often as an economic alternative to transmission or distribution system expansions or significant generation capacity additions. Often considered an alternative to large central generating plants.

**Economy power**—Generally non-firm energy purchases made from off-system where the purchase price would be below the purchaser’s marginal cost of generation. One typical example would be purchases of hydroelectric power generated by fish flows or releases made to increase storage availability. Absent the purchase, the energy would often be lost.

**Environmental externalities**—Environmental costs associated with electricity production, distribution, and consumption that are not reflected in the commodity price. Examples include the cost impact of various air emissions on human health, crops, and natural ecosystems. Their costs could

be that of the damages themselves, the economic losses that ensue from the damages, the remediation of or response to the damages, and/or the intrinsic loss of value in destroyed or radically altered environments.

**Firming, Firm-up**—The use of other system resources to compensate for the variability of intermittent resources such as wind.

**Flow-based contracts**—Contracts that specify only the amount of energy to be delivered without identifying specific line segments.

**Functionally unbundle**—To separate the ownership of electrical generation resources from ownership of transmission and distribution facilities primarily through regulatory requirements other than mandatory divestiture.

**Island**—A condition where, due to the partial loss of generation or portions of the transmission network, some generation resources and nearby load are isolated from the rest of the network and resources.

**Level playing field**—No party to a transaction is the recipient of incentives, subsidies, or other advantages which are not received by all other parties.

**Load centers**—Areas of concentrated electricity demand such as major cities.

**Native load customers**—The wholesale and retail customers on whose behalf the transmission provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the transmission provider's system to meet the reliable electric demand of such customers.

**Netted out**—Subtracted from.

**Network Integration Transmission Service (NITS)**—Whereby the control area of the transmitting utility functions like a pool and NITS transactions are primarily an issue of load balancing.

**Open access**—The requirement that public utilities owning and/or controlling facilities used for the transmission of energy in interstate commerce provide non-discriminatory third-party access to such facilities.

**Pancaking**—The multiple charges that result from being subject to multiple tariffs or zones when transmitting energy from resources to loads.

**Point-to-point**—The reservation and/or transmission of energy between contractual points of receipt and delivery on the transmission provider's system.

**Point-to Point Transmission Services (PPTS)**—That support bilateral arrangements between generator and purchaser.

**Postage-stamp pricing**—The use of a single unitized charge regardless of the distance between the generation resource and the load.

**Ramping, Ramp-up**—The process of gradually increasing or decreasing the output of system resources. The rate at which the output of system resources increases or decreases is called the ramp rate.

**Real-time marginal spot price**—As used in this context, the instantaneous cost of producing or not producing an incremental unit of energy for a short period of time.

**Rolling window**—Most dated unit of time within the measurement period is dropped and the most recent unit of time is added, making the resulting measurement period current.

**Spinning reserves**—Reserve generation capacity that is spinning, synchronized to the grid, and ready to take up load. Public utilities maintain spinning reserves in order to account for load forecast uncertainties and possible outages of other generating plant.

**Stranded transmission capacity**—Transmission capacity that is contracted for but unused.

**Subfunctionalized pricing**—The imposition of access fees based on the value of individual assets utilized along a specific transmission path.

**Take or pay**—Contracts that maintain the tradition of requiring a take-or-pay reservation of firm transmission capacity require advance commitments to transmission which are difficult for intermittent technologies.

**Turnkey**—Turnkey preparation of a facility or system means that a single contractor acquires and sets up all necessary premises, equipment, supplies, and operating personnel to bring a project to a state of operational readiness. In some cases, the contractor may continue to operate the facility for the customer, or the customer may assume operational control.

**Universal truths**—Undisputable facts or conditions known to all.

**Wheeled, Wheeling**—Moving or transmitting electricity.

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