Transmission Pricing Issues For Electricity Generation From Renewable Resources

Abstract

This article discusses how the resolution of transmission pricing issues which have arisen under the Federal Energy Regulatory Commission's (FERC) "open access" environment may affect the prospects for renewable-based electricity. After giving some preparatory material on the deregulated electricity market and on renewable energy characteristics relevant to electricity transmission, the article discusses alternatives being considered for pricing transmission, provides qualitative impacts of those choices on renewable electricity transmission costs, and concludes with alternatives for reducing renewable-based electricity transmission costs.

Introduction

Historically, transmission pricing has not been a concern for renewable generating facilities. Most renewable generation (excluding hydroelectric) in the United States has been developed, owned, financed, and operated by nonutility generators (NUG). Renewable NUG power plants generally have operated under FERC's "qualifying facility" (QF)[1] status , selling their power to the utility in whose service territory they were located. Utilities purchased this power under long-term contracts at a specified rate that included all transmission services (bundled rates).

Now, however, FERC's "open access" policy makes transmission lines available competitively and requires various transmission services to be priced separately from generation.[2] For a couple of reasons, it is important to consider how new transmission pricing schemes may affect renewables. One major reason is that substantial growth in renewable-based electricity could occur under a number of Federal and State electricity restructuring and greenhouse gas reduction proposals.[3] Many States are presently establishing policies affecting renewables (e.g., renewable portfolio standards, system benefit charges), and more States are expected to follow. The Administration has proposed a Federal electric restructuring plan that includes renewable incentives. These policies will also result in new renewable capacity. Growth is expected in renewable-based electricity under these scenarios, even though in most circumstances renewable-based generation is considerably more expensive than fossil fuel-based electricity. But even if such programs do not materialize, the limited opportunities where renewables can be economically competitive with conventional generation represent substantial growth potential from the present renewable electricity base.[4] Since large quantities of (non-hydro) renewable electricity may be on the horizon for the first time, concurrent with a radical change in electricity market structure, examining the impact of transmission policies on renewable-based electricity seems timely.

1 The Public Utility Regulatory Policies Act of 1978 (PURPA) facilitated the emergence of certain electricity-producing companies called qualifying facilities (QF). QFs are defined as small power producers and cogenerators. To maintain QF status, small power producers must obtain at least 75 percent of energy inputs for electricity generation from renewable resources (geothermal, biomass, wind, solar, or hydropower) and have an installed capacity of less than 80 megawatts. QF's receive certain benefits but must meet specific ownership, operating, and efficiency requirements established by the Federal Energy Regulatory Commission (FERC). One benefit requires the host electric utility to purchase the output of the nonutility at the utility's "avoided cost."

2 FERC's "open access" policies were promulgated in two rulings, known as Orders 888 and 889. See National Renewable Energy Laboratory, "Open Access Transmission and Renewable Energy Technologies," by Kevin Porter, NREL/SP-460-21427, Golden, CO (September 1996). The website for this document is: http://www.nrel.gov/research/ceaa/emaa/open_access/index.html.

3 Energy Information Administration, *Annual Energy Outlook 1998: Issues in focus*, http://www.eia.doe.gov/oiaf/aeo98/issues.html#issues2; and Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets and Economic Activity*, SR/OIAF/98-03, Washington, DC, (October 1998)

4 The cost for wind generation is estimated at 5 cents/kWh or less at some sites, depending on the methodology used (i.e., inclusion of a production tax credit, various financial incentives, financing, availability and price of land). Also, renewables typically (but not always) compete with natural gas, which is not always available in some regions (i.e., parts of the Pacific Northwest and New England). In these regions, renewables compete reasonably well.

Second, while transmission costs are only about 2 percent of total utility operating and maintenance costs,they represent 12 percent of total electric plant in service.[5] Thus, to the extent that renewables require or cause changes in transmission and distribution equipment from those which would occur if a similar amount of conventional generation were added, the impact on electric plant could be nontrivial.

Already, some transmission issues have surfaced with these projects, and more can be expected. Most of these issues relate to three characteristics of renewable-based generation: (1) Availability–due either to the intermittent nature of many renewables or the expected capacity factor; (2) Distance of the resource from load centers; and (3) The relationship of electricity demand to maximum output potential from certain renewable sources.

In addition, marketing strategies to promote renewables, possible now under FERC's open access environment, create some issues unique to renewables. For example, customers willing to pay a premium for renewable energy and the renewable facilities providing them power may be in different regions. This is quite possible because of marketing efforts to "bundle" such customers, who may cross transmission regions. Either bundling customers or building capacity requires reserving transmission capacity, and that is typically not contracted for until after the green marketing campaign is announced or a commitment to a new renewables facility is made.

Thus, for a variety of reasons, transmission issues for renewables in a restructured electricity market are of current interest.

Background

Electricity Restructuring

The transition to a fully competitive wholesale market for electricity is altering the purchase and sale of electricity, as well as transmission services. Regarding generation, long-term contracts specifying generation facilities will likely be replaced by short-term contracts, based on spot market prices and quantities. Also, "merchant" facilities are being built with either no pre-existing contracts for power, or contracts for only a small percent of the power output. Another change is that power from a single facility may be sold to multiple customers, rather than under than a single long-term contract to a purchasing utility.

The outlook for transmission services is totally different. Even though the FERC has ordered electricity transmission facilities to be made available to all generators on comparable terms ("open access") and transmission services to be operated and priced independently of generation ("unbundling"), transmission rates will continue to be regulated. Hence, transmission facilities will be built partially based upon the expectation that such investments will be recovered through traditional rate-making procedures. However, there is no consensus at present on the appropriate way to price transmission services in order both to provide incentives for investment in needed transmission facilities and to utilize transmission facilities efficiently.

With access to the transmission system being opened,[6] transmission facilities and the transmission operator assume a much more important role compared to their role under a regulated monopoly environment. There are greater opportunities for expanded wholesale trade with lower cost generation replacing higher cost generation in expanded geographical regions and transmission systems when capacity and systems operation constraints permit. The establishment of independent system operators (ISO) and transmission protocols should encourage the entry of new buyers and sellers increasing bulk power (wholesale) transactions.

Transmission pricing is likely to have mixed effects on the total cost of renewable-based electricity transmission charges. Many electric generating facilities using renewables are "qualifying facilities" (QFs) under the Public Utility Regulatory Policies Act (PURPA). PURPA guarantees that these qualifying facilities can sell their electricity to the host (local) utility. Renewable generating facilities however, may benefit from open access and transport electricity to a more favorable competitive market than a "host" utility. Under open access, renewable energy generating facilities can use the

[5] Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1997,* DOE/EIA-0437(97), Washington, DC, (December 1998).

[6] Open access to transmission facilities is limited as FERC has jurisdiction over only investor-owned utilities. Municipal and cooperative electric utilities are not required to provide open access unless under reciprocity. Open access is also subject to system integrity requirements. Some utilities reserve some transmission capacity for reliability reasons, otherwise known as capacity benefit margin (CBM), which has caused some controversy.

transmission system to sell power to any utility. In States where "retail" competition is permitted, electricity may also be sold to any retail customer. Thus, provided transmission access is available and at a competitive price, customers who want renewable-based power (such as in "green power" programs) will be able to purchase it directly from a renewable power supplier.

The other side of open access transmission is that there will likely be a greater number of buyers and sellers, including new categories of players such as "green power" marketers and power brokers. This will increase competition and exert a downward pressure on electricity prices, placing higher cost renewables at a disadvantage. Although electricity from renewable energy will have access to more markets, renewable generating technologies will face stiff price competition from other generating technologies. Some of this competition may be ameliorated, however, if Federal and/or State restructuring legislation includes renewable portfolio standards (RPS) or other renewable provisions to support renewable energy such as system benefit charges.

For a discussion on the history of open access transmission, see the report, "Open Access Transmission and Renewable Energy Technologies." [7]

Characteristics of Renewable Resources for Siting Generating Facilities

Another factor related to transmission of particular importance to renewables is generation facility siting. Renewable resources for power generation are site-specific in ways distinct from conventional sources. Oil, gas, coal, and uranium can economically be transported over most of the country, so generation facilities using these sources can be located where electricity demand and other considerations dictate.[8] In contrast, renewable resources either cannot be moved or can be moved only short distances at reasonable cost. Each renewable resource is distinct in this regard, as will be discussed below.

The largest source of renewable electricity is conventional hydroelectric power (approximately 80 percent). Hydro power growth is constrained by the lack of available new sites, high construction costs, growing environmental concerns, and competing uses for water resources. Remotely located, run-of-river sites with limited intermittent electric capacity are generally not economically viable.

Biomass includes all organic material stemming from plants, trees and crops (including wood and wood waste) that is available throughout much of the United States. The high costs associated with handling, transporting, and storing large quantities of biomass effectively negate any scale economies associated with building large conversion facilities. As a result, many biomass generating facilities are built to support biomass-related industrial applications (e.g., paper and paper products) where feedstock costs are either low or negative.[9] These facilities tend to be located remote from electricity demand centers, so the cost of constructing additional transmission facilities for selling excess power is often high. In the near term, the largest market for "pure electric" use of biomass is co-firing in low percentages at fossil-fired electric generating facilities.

U.S. wind, solar, and geothermal resources are shown in Figures 1, 2, and 3, respectively. Areas potentially suitable for wind energy applications are dispersed throughout much of the United States (Figure 1). However, only areas designated "Class 4" or greater are suitable for wind turbine technology currently under development. These areas are constrained by land availability, transmission and access constraints, public acceptance, environmental, and other technological and institutional constraints.

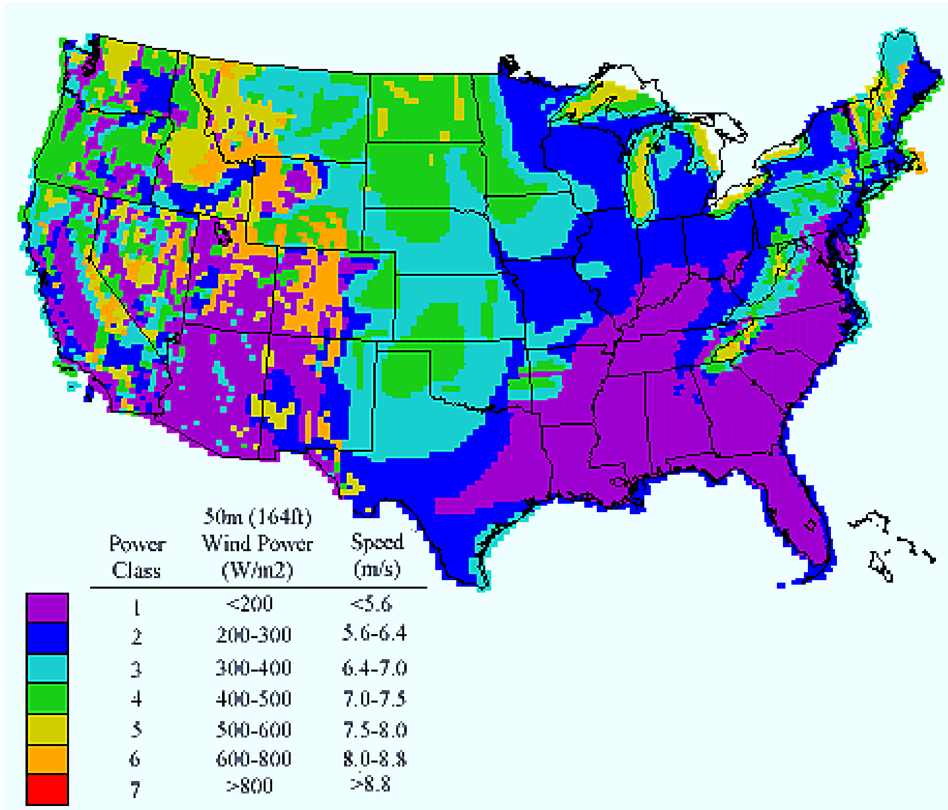
Siting is a two-edged sword for solar thermal and photovoltaic (PV) electricity. On the negative side, viable solar thermal resources are limited to the southwestern United States (Figure 2), where water availability (for solar thermal utilizing steam turbines) limits power generation potential. However, most of the country is suitable for producing electricity using solar PV during daylight. Further, PV generating facilities can be installed at the point of demand, with back-up power provided by conventional sources elsewhere on the

[7] National Renewable Energy Laboratory, by Kevin Porter, NREL/SP-460-21427, Golden, CO (September 1996). The website for this document is: http://www.nrel.gov/research/ceaa/emaa/open_access/index.html.

[8] A number of issues not related to this article that can affect facility siting, such as land use around metropolitan areas, water usage and quality, etc.

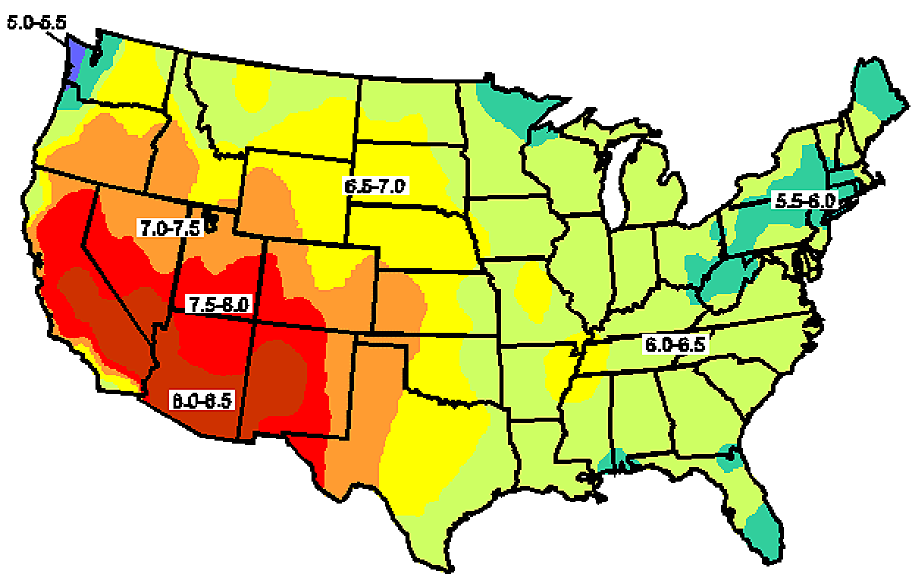
[9] A considerable amount of biomass consumed for energy is waste from other industrial processes. As such, energy production from biomass is a waste disposal alternative, and the "pure" energy cost is the total cost of energy production less the cost of other waste disposal options (which in some cases may have many regulatory constraints placed upon them).

Figure 1. U.S. Annual Wind Power Resources



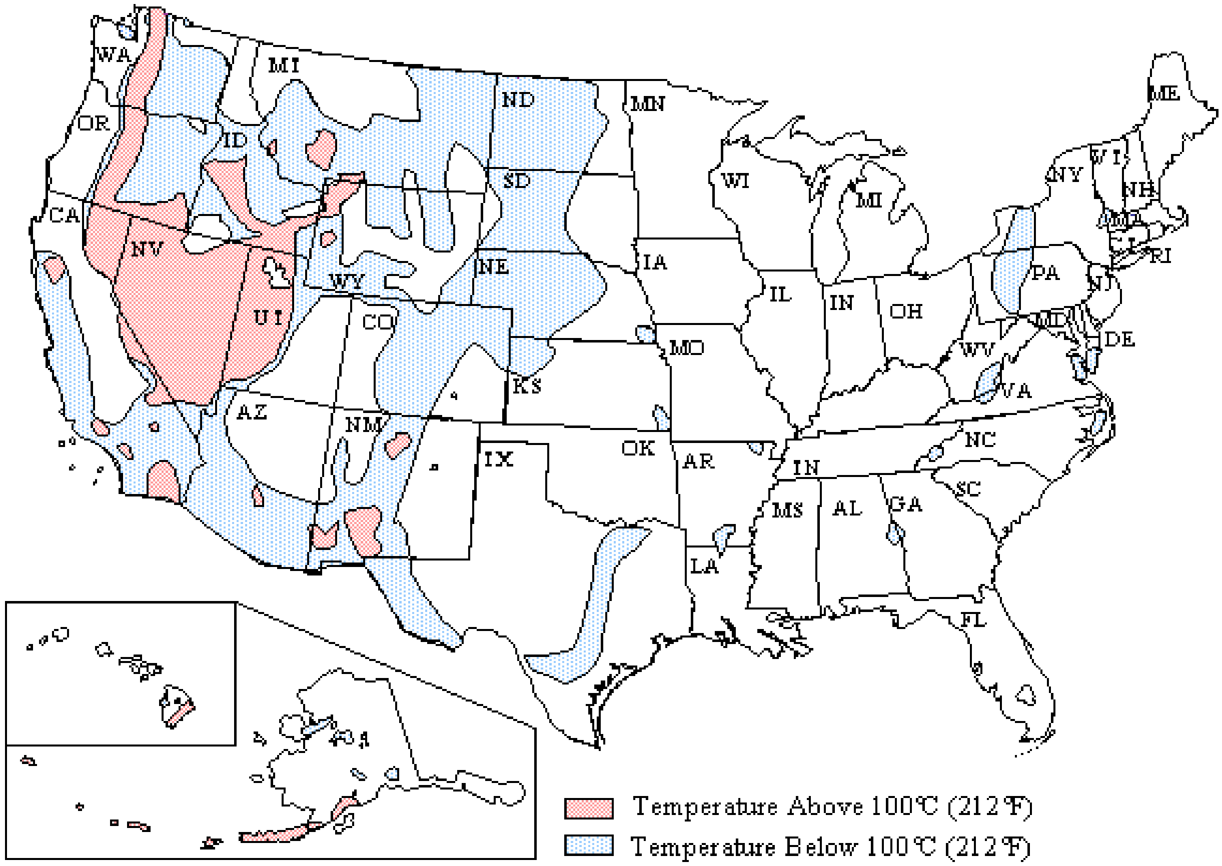
Source: National Renewable Energy Laboratory.

Figure 2. U.S. Solar Resources



Note: Measurements indicate the average radiation received on a horizontal surface across the continental United States in the month of June as measured in kilowatthours per square meter.
Source: National Renewable Energy Laboratory.

Figure 3. U.S. Geothermal Resources



Source: Geothermal Heat Pump Consortium.

system.[10] Hence, PV electricity is the renewable gener ating technology least likely to be affected by transmission pricing policies. However, how retail transmission access and distributive utility concepts evolve (e.g., net metering policies[11]) could have a significant impact on PV electricity.

Economically feasible, high-temperature geothermal resources occurring mostly west of the Rocky Mountains (Figure 3) are more limited in scope than either wind or solar. Further, the nature of using geothermal resources is such that the generating plant must be located at the hot water site. Hence, siting is more constrained for geothermal than for other renewable resources used to generate electricity. Another constraint on geothermal power use is that generating plants using so-called "high-temperature" geothermal resources are relatively inefficient causing geothermal production costs to be comparatively high relative to fossil-fueled steam plants. The economic feasibility would be further limited if investment in constructing long transmission access lines were required.

Characteristics of Renewable Generating Facilities

Compared with conventionally fueled generating facilities, many renewable facilities (excluding some biomass and hydro power) have different design and operating characteristics. These generally include: lower and more highly variable capacity factors, intermittent availability, and longer distances from existing transmission lines and/or load centers. A characteristic specific to wind

[10] Non-transmission issues involving back-up power are significant but are beyond the scope of this article.

[11] Measures the difference between the total generation of a facility and the electricity consumed by the facility with a single meter that can read electricity flows in and out of the facility.

and solar/PV resources is that their availability tends to be greatest when demand for electricity is highest (daytime in the South and West). The coincidence of maximum resource availability and peak demand offsets some of the other negative characteristics for solar/PV and wind. Also, biomass and geothermal facilities often run at capacity factors closer to that of conventionally fueled generating plants. However, as geothermal operations mature at a given site, the water temperature/pressure can decrease, driving up the heat rate even further and decreasing the portion of the demand curve over which plant operation is viable.

Transmission Pricing

This section provides principles for transmission pricing, examines transmission pricing options, and discusses the role which the new Independent System Operators (ISO) will play in transmission and what practices the recently created ISO's have adopted.

Pricing Concepts

Although transmission costs represent only about 2 percent of an investor-owned utilities' operating expenses, they are nonetheless important. Workable competitive power markets require ready access to a network of transmission and distribution lines that connect regionally dispersed end-users with generators. Because power flows at one location impact electric transmission costs across the network, transmission pricing may not only determine who gets access and at what price but also encourage efficiencies in the power generation market.

Transmission constraints can prevent the most efficient plants from operating. These constraints also can determine the location of generation that affect the amount of power losses for transmission. Transmission prices that ignore these concepts will produce an inefficient system. Transmission pricing that considers transmission constraints (congestion pricing) should encourage the building of new transmission and/or generating capacity that will improve system efficiency.

In addition to meeting revenue requirements, transmission pricing should ideally do the following:

- promote efficient day-to-day operation of the bulk power market
- encourage investment and determine location of generation
- encourage investment and determine location of transmission lines
- compensate owners of transmission assets; and
- be fair and practical to implement.

The pricing options below should be evaluated with these criteria in mind.

Pricing Options

The simplest and most common type of transmission pricing is postage stamp pricing. A postage stamp rate is a fixed charge per unit of energy transmitted within a particular zone, regardless of the distance that the energy travels. Transmitting across several utility systems or zones and accumulating utility or zone access charges is often called "pancaking." Postage stamp rates are based on average system costs and may have a variety of rate designs, based on energy charges (cents per kWh), demand charges (cents per kW), or both energy and demand charges. Rates often include separate charges for peak and off-peak periods, may vary by season, and, in some cases, set different charges for weekday versus weekend and holiday usage. Transmission services also are generally offered on both a firm and non-firm basis. Firm transmission service guarantees service subject to emergency curtailments or system congestion. In contrast, non-firm transmission service is more economical than firm service, but is subject to curtailment or interruption, often with little or no notice by transmitting utilities.

Historically, firm transmission service contracts were long term. Non-firm agreements can be either short or long term. Under FERC Order 888, utilities are required to offer both point-to-point and network transmission service. Point-to-point service has specified points of delivery and receipt, transmission direction, and quantities. Network service typically is negotiated through a longer-term contract and involves flexible delivery points and quantities. Network service typically is arranged to meet a wholesale customer's varying native load requirements. Thus, even with a postage-stamp rate, the terms and conditions of posted prices may vary substantially.

Traditional transmission pricing is based on a routing scheme known as a "contract path." A contract path rate is one which follows a fictional transmission path agreed upon by transaction participants. Contract path pricing may be selected to minimize transmission charges and also to avoid "pancaking." However, contract path pricing does not reflect actual power flows through the transmission grid, including loop and parallel path flows.[12]

An alternative is "flow-based pricing." One type is "megawatt-mile" pricing, where the transmission rates explicitly reflect the cost of transmission, based on both the megawatts of power flow and the distance between the receipt and delivery points. The cost of transmission per megawatt-mile is the total cost averaged over megawatt miles of usage.

Much of the interest in transmission pricing reform involves moving away from utility-by-utility contract path pricing to regional transmission tariffs based on power flows, as well as "congestion pricing." Congestion pricing sets transmission rates to allocate limited transmission capabilities over constrained interfaces to those transmission customers that most value the ability to make power transfers. Thus, rates increase as the demand for electricity transmission increases and the system is used efficiently. Congestion on transmission systems is not reflected in either the postage-stamp or megawatt-mile pricing described. Prices that do not increase as congestion increases will tend to allocate the transmission capacity inefficiently, because available capacity is not necessarily allocated to the user for which the transmission has the greatest value.

Congestion costs can either be assigned directly to users causing the congestion or shared among all users. When the transmission system becomes congested so that no more power can be transferred from a specified point of delivery to a specified point of receipt, more expensive generation may have to operate on one side of the transmission constraint than the other. In a competitive market, regardless of the form of transmission pricing utilized, this would create a difference in generation prices between the two locations. (Any lower cost power generated on one side of a constraint could be sold at the higher price on the other side of the constraint, assuming the difference exceeds the transmission cost, in the absence of the congestion.) The difference between these electricity prices is the "economic price of transmission." It reflects the cost of congestion and losses. In the absence of congestion pricing for transmission service, these "economic rents" would represent a windfall to the generation suppliers that are able to sell through the congested interconnection. As a result, transmission prices will recover congestion rents from those suppliers who are able to complete transactions through the constrained interface.

There are many ways to allocate revenues from congestion pricing. In California, such revenues are used to reduce the access fees that all transmission customers pay. Another proposal is to create a system of transmission congestion contracts. These would establish comprehensive set of rights to either make power transfers or receive compensation for the inability to do so through redistribution of congestion rentals to the holders of transmission congestion contracts.

Development of Independent System Operators

The electric power industry has increasingly accepted the concept of an "Independent System Operator" (ISO). An ISO is created when transmission-owning utilities transfer operating control (not ownership) over designated transmission facilities to an independent nonprofit organization. The expected benefit of an ISO is to ensure equal and fair access to the transmission system precluding discriminatory practices and reducing self-dealing and other market power abuses. Currently, six ISOs are operating and a number of ISOs are in different planning stages. The six operating ISOs are: California ISO; Electric Reliability Council of Texas (ERCOT) ISO; Pennsylvania, New Jersey, Maryland (PJM) ISO; New England ISO; New York ISO and; Mid-America Interconnected Network (MAIN) ISO.

The responsibilities of ISOs are very broad, going beyond the role of ensuring equal and fair access to the transmission system. To obtain the FERC's approval, an ISO must comply with generic principles provided in Order 888, although the ISO has latitude in the detailed implementation. ISO functions can be classified broadly under two categories: the facilitation of a wholesale power market, and the control of the transmission grid and related facilities. The relative importance of the functions within these two categories, and the details of how they are performed, vary among ISOs.

[12] Electricity flows on all available transmission paths between generators and points of use according to the laws of physics. The actual flow of electricity is referenced as flowing "parallel" to contractual paths (transmission paths) that are reserved for the flow of electricity, but are not actually used.

Transmission Pricing Through an ISO

Most ISOs have proposed "zone pricing," at least as an interim method before single-system pricing. With zone pricing, the transmission grid is divided into zones, and the transmission customer pays one rate based on the zone where the energy is withdrawn, regardless of how many zones in the ISO are crossed. The PJM-ISO has defined 10 zones corresponding to the service areas of the transmission owners in the ISO. The rates for a particular zone are based on the revenue requirements of the transmission owners in the zone. While zone pricing is practical and meets the revenue requirements of the transmission owners, it does not necessarily allocate cost fairly among the users of the transmission system.

Zone pricing, in some instances, is considered an interim method. FERC recommended a system-wide uniform rate without zones, based on the average revenue requirements of transmission owners across the ISO region. However, an average uniform price may result in "cost shifting" when the revenue requirement of high- and low-cost transmission owners are averaged. Zone pricing, or a uniform rate, also does not account for or resolve parallel power flows. FERC's guidance was that PJM-ISO should eventually change to pricing based on electrical characteristics and power flows instead of boundaries.

Some regions planning to create an ISO have proposed using a megawatt-mile method for pricing transmission (e.g., Southwest Power Pool, Mid-Continent Area Power Pool). This approach is a distance-based method that takes into account parallel power flows using power flow modeling techniques. This method gives no credit for counter flows and is administratively much more complicated than other methods, as each transaction must be calculated; rates must therefore be re-calculated for each change to a transaction or each additional transaction.

Three methods for pricing congestion have been proposed by the ISOs.

- The PJM and New York ISOs are using location-based marginal pricing (LBMP). LBMP is based on the cost of supplying energy to the next increment of load at a specific location on the transmission grid. LBMP determines the price that buyers will pay for energy in a competitive market at specific locations, and measures congestion costs by taking the difference in the LBMP between the two locations. When no congestion exists, the LBMP will be the same at each location.

- The California ISO divided its region into congestion zones. Transmission constraints are small within each zone but large between zones. A usage charge is imposed on all customers who send energy across zones. The charges are determined from bids voluntarily submitted by a scheduling coordinator to increase or decrease power generation in their zone at a specified cost.

- The New England ISO bases congestion charges on the cost of out-of-merit dispatch. Costs are allocated to each load based on the percent each load represents of the total load. Though this method is simple to implement, it does not produce price signals on how to alleviate the congestion. However, New England ISO does not have a significant transmission congestion problem.

The Federal Energy Regulatory Commission and other industry participants seem to view the concept of an ISO as the solution to open-access. However, ISOs are going through an evolution. Not only are there significant differences in the operations and pricing schemes among existing ISOs, there are also differences in the operations and pricing schemes for proposed ISOs. Recently, the Department of Energy (DOE), by Section 202(a) of the Federal Power Act that gives DOE the authority to divide the country into regions for purposes of reliability transmission, gave FERC authority to establish boundaries for ISOs.[13] The DOE believes that providing FERC with authority to establish boundaries for ISOs or other appropriate transmission entities could aid in the orderly formation of a properly-sized transmission institutions and enhance the development of ISOs in a rational, comprehensive manner. Also, by helping FERC in addressing reliability issues, the reliability of the transmission system would be increased.

Impact of Transmission Pricing on Renewable Electricity Transmission Costs

A problem with pricing transmission to provide the proper signals to the electricity market–for any type of

[13] Megawatt Week, Monday, October 5, 1998.

generation—is that the marginal cost of transmission for completing any given power transfer typically is only a fraction of the embedded costs included in transmission tariffs. Actual transmission pricing schemes set rates well above marginal cost to recover the fixed costs of the transmission system as well. The methodology used to recover fixed costs (in excess of marginal costs) can change the allocation of costs among different types of generation.

In general, transmission charges will be related to one or more of the following: the distance electricity is transmitted; the amount of electricity transmitted; and the reservation, if any, made by the generator for access to transmission lines (known as "capacity reservation"). How these pricing schemes would affect the cost of renewable-based generation depends upon how the characteristics of renewable generation—intermittence and capacity factor, distance from load centers, and coincidence with peak load—relate to these factors.

Intermittence and capacity factor. The capacity factor of a power plant is the amount of energy actually produced divided by the total amount of energy it could have produced operating at full capacity over a specified time period. Certain technologies using renewable resources, such as wind and solar, operate intermittently as the resource is available. This results in relatively low capacity factors. Other technologies, such as internal combustion or gas turbine, are used intermittently and at low capacity factors to serve specific loads. However, these technologies have more flexibility than wind or solar to match load on a steady basis, and thus can schedule output to coincide with reserved transmission capacity. Pricing schemes that have high firm (take-or-pay) charges for transmission capacity could reduce the competitiveness of intermittent/low capacity factor generators. Under take-or-pay arrangements, also known as capacity-based pricing, a fee is paid for the total capacity reserved, regardless of the amount of energy transmitted. The intermittent operation of some facilities means that these power producers could pay a significant amount for unutilized capacity under capacity-based contracts.

If access fees are based on energy, then intermittent renewables will pay only for transmission services equal to their energy output. This would increase the competitiveness of intermittent renewables but raises an issue of fairness related to another transmission pricing concept: scheduling. Generators which can schedule electricity transmission far in advance generally pay lower rates. Renewables with high intermittence are unlikely to find advanced scheduling feasible, as it generally involves capacity-based charges in exchange for firm service. Purchasing non-firm transmission service is a possibility and is discussed extensively later in the report.

Distance from load centers. Certain renewable resources tend to be located further from large areas of electricity demand. Geothermal and wind resources often fall into this category. Because it is inefficient to move biomass resources more than 50 miles for fuel to generate electricity, distance from load centers is also an issue for biomass. However, because many industrial applications of biomass-based electricity occur in the pulp and paper industry where facilities are located in forested areas, this is less of an issue than it is for geothermal and wind.

Under distance-based transmission pricing schemes (e.g., zone and megawatt-mile), remotely generated electricity will incur high transmission costs. Offsetting this disadvantage is that within the areas of resource availability (especially wind, solar, and certain types of biomass), renewable facilities can locate competitively at remote locations, where the cost of bringing in conventional fuels or building transmission/ distribution facilities is quite high.

If congestion pricing is adopted, then the marginal price of utilizing the last few increments of transmission capacity may be quite high. This could encourage "distributed generation "(small generators located along the distribution system) to help reinforce transmission and/or distribution systems, rather than large central power plants. Wind and photovoltaic technologies are ideally suited for such applications, given resource availability. Micro gas turbines may also be able to compete in such applications.

Coincidence with peak load. The price for transmission capacity is significantly affected by capacity demand according to the time of day. Certain technologies using renewables have little flexibility in determining the intermittent periods when they operate.[14] Transmission congestion, though generally occurring during periods of peak load, may also occur at other times. Technologies whose intermittent availability follows system load are said to have a "high coincidence." Under congestion pricing, facilities with a high coincidence with system peak are likely to incur higher transmission costs than

[14] Fortunately, renewable availability sometimes occurs coincident with peak demand. An example is solar-based electricity, which is generally feasible in the southwestern U.S. where peak demand occurs during daylight hours.

those with lower coincidence with system peak. However, higher transmission costs may be offset by higher payments for electricity delivered during peak demand periods.

The challenge for designing access fees to recover fixed costs is to send generators and end users price signals that reflect the true cost of electricity and using the transmission / distribution system. The next section provides some possible transmission pricing schemes which would lower renewable electricity transmission costs while following the pricing concepts mentioned earlier.

Alternatives to Reduce Transmission Costs for Renewable Electricity

Under current transmission pricing, most generation is sold through take-or-pay, capacity-based transmission charges to reserve firm capacity. Generators using renewables with intermittence and low capacity factors generally have high transmission costs per unit of electricity generated under these pricing schemes. Under capacity-based pricing schemes, generators using renewables pay for unutilized capacity when the renewable resource is unavailable. Alternatives to reduce transmission costs include purchasing non-firm transmission service, buying firm service that matches generation patterns (if available), selling unutilized transmission capacity in a secondary market, and selling power to a power marketer which bundles generation produced by several small facilities.

The alternatives to renewable facility owners purchasing firm services may, however, be limited by financing considerations. In traditional electricity markets, renewable facility owners would first obtain qualifying status from FERC. Because PURPA requires the host utility to purchase a QF's output at avoided cost, the facility has a virtual guarantee on selling its power, paving the way to obtain project financing. If transmission is bid and purchased competitively, however, it may be necessary for renewable (and perhaps other) facilities to purchase firm transmission capacity as a condition of obtaining financing. Another option could be for facilities to obtain insurance (if available) against the times when generation is available but transmission is not.

Generally, non-firm transmission is scheduled, and no advance capacity reservation is needed. The ability to accurately schedule non-firm transmission service to meet a generator's forecast of output depends on the predictability of the availability of the generation and the advance notice and duration of the reservation required by the transmission provider. Scheduled non-firm service that matches the output of the generator would be analogous to an energy charge where the generator pays for the service used. Generators that use intermittently available resources, such as solar and wind that varies from hour to hour, would need to be able to schedule non-firm service on short notice. However, scheduling non-firm service on short notice and for brief durations can result in both availability and price risk.

The FERC has authorized an effort to test the feasibility of hour-ahead transmission scheduling. On September 29, 1998, it approved a request of the Commercial Practices Working Group (CPWG) of the North American Electric Reliability Council for a four-month experiment, starting November 1, 1998, for handling next-hour requests for transmission service. In accepting CPWG's proposal, FERC stated: "If the transmission provider is not able to respond consistently to customers' reservations or schedule requests for hourly transmission service within 15 minutes of queue time, then the customer retains the option of providing the transmission provider with a confirmation of the reservation or schedule by means of telephone or facsimile. If a reservation is entered or confirmed by telephone or facsimile, the transmission provider may require the customer to enter the reservation on the OASIS electronically, after-the-fact, within one hour of the start of the reservation. It is up to the transmission provider (and not the individual customer) to determine whether it can consistently handle such hourly transmission service requests within 15 minutes during the pendency of the experiment. If a transmission provider cannot respond consistently within 15 minutes, the transmission provider cannot require customers to enter reservations and schedules electronically prior to the scheduling deadline."

Buying firm service that matches generation patterns. Generators that use renewables with predictable resource availability (i.e., geothermal, biomass) may be able to minimize transmission costs by purchasing firm transmission based on the anticipated output. This option is based on the predictability of the renewable resource compared to the advance notice and duration of the reservation required by the transmission provider to reserve firm service.

Selling unutilized firm transmission capacity in a secondary market. Some of the cost of unutilized firm transmission capacity can be recovered through the sale of the unutilized capacity in a secondary market. Selling transmission services in a secondary market entails both a price risk and the risk of being unable to find a buyer. This would be even more difficult for facilities using renewable resources such as wind or solar that have unpredictable availability. FERC's price cap on capacity reassignments that limit the capacity holders' profits through reassignment also makes this option less attractive.

Selling power to a marketer. Most generation using renewables is built by non-utility generators that do not have a diversified generation profile. In contrast, utilities or power marketers may purchase generation from renewable resources as part of a generation portfolio. The utilities' or power marketers' diverse portfolio allows them to purchase and utilize transmission services more efficiently.

Summary

The transition from bundling electricity transmission and generation costs to a market where transmission is owned and priced separately could have major impacts on the quantity and location of renewable-based generation. Even though transmission costs only represent about 2 percent of total electricity costs currently, transmission availability and access issues can alter where generation can be feasiblely placed on the transmission system.

Renewable resources tend to exhibit the following characteristics different from conventional fuels used to generate electricity: they are often located remotely from electricity demand centers and cannot be "shipped" feasiblely, if at all; they are often available only intermittently; and some renewables tend to be available in approximate coincidence with electricity demand (peak coincidence). Remote location increases the cost of transmitting power under distance-based pricing schemes. Intermittent availability either increases the cost of providing electricity or increases the risk that transmission capacity will not be available whenever renewable generation is. The peak coincidence of some renewables (e.g., solar, wind, photovoltaic) with electricity demand could raise transmission costs under congestion pricing schemes, but the price received for peak electricity may well offset or exceed the higher costs.

Alternative pricing schemes which could reduce the cost of transmitting renewable-based electricity include purchasing non-firm transmission service, buying firm service that matches generation patterns, and selling unutilized firm transmission capacity in a secondary market.

FERC has authorized a trial of hour-ahead transmission scheduling. Scheduling anything other than firm service could have an impact on proposed renewable projects, because project financiers have traditionally assumed that transmission access was guaranteed for renewable NUGs.