Discussion Paper

Queuing Practices and Alternatives to Link LSE Resource Plans and Transmission Planning

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Executive Summary

The Federal Energy Regulatory Commission's (FERC) policies on queuing for interconnection and transmission service provide fair methods for allocating scarce transmission resources, but have the unintended consequences of creating a hurdle to the development of cost-effective transmission, hampering the implementation of state generation policy objectives, and increasing costs. Effective interconnection and transmission service queuing processes are particularly important for wind development because the construction of new wind generation is accomplished much more rapidly than other generation sources, such as natural gas power plants and coal power plants. Additionally, wind generation additions are typically in smaller sizes that gas or coal additions.

There are several potential remedies that should be further explored:

- Give preferential treatment in queuing processes to those generating projects that have been selected pursuant to transparent, state-approved resource plans and related Requests for Proposals.

- Expand the use of the open season process as an alternative to FERC's first-come-first-served queue rules and as an extension of the clustering option.

- Encourage transmission providers to group interconnection requests and transmission service requests to identify cost effective investments. Southern California Edison's proposal for a renewable trunk line proposal in the Tehachapi region in California provides a role model to identify transmission investments in advance of future generation requests.

- Consider modifications to FERC rules that would allow the transmission and resource planning functions of vertically-integrated utilities to discuss transmission needs associated with new generation being considered to serve the utility's load. Rule modifications would allow such communication provided it is transparent to outside parties and part of a state-approved resource planning and acquisition process.

1. FERC Policies Affecting the Queue for Interconnection and Transmission Service

To provide non-discriminatory access to the transmission system FERC has adopted first-come-first-served policies governing the interconnection of new generation to the grid and request for transmission service. FERC has recently updated its policies on interconnection with the issuance of separate orders governing interconnection of generators greater than 20 MW and less than 20 MW. Its policies on processing of transmission service requests are governed by the provisions of Order 888, originally issued in 1996.

FERC has also issued codes of conduct governing communication between a company's merchant and transmission functions. While necessary to prevent preferential treatment for a company's own generation, the codes of conduct have limited communication between generation and transmission development to the detriment of efficient development of generation and transmission identified in state-approved utility resource plans.

Order 888 and the Transmission Service Queue

In 1996, FERC issued Order No. 888 with the dual purpose of remedying undue discrimination in access to monopoly owned transmission system and promoting competition in wholesale electricity markets.[1] In combination with Order No. 889[2], FERC required all transmission owners and operators to (1) file open access non-discriminatory transmission tariffs that contain terms and conditions of non-discriminatory service, (2) execute their own wholesale sales and purchases of electricity under the open access tariffs, (3) functionally separate transmission from generation marketing functions and communications, and (4) develop a open access same-time information system (OASIS) that provides all transmission market participants access to specified information about transmission services.

Order 888 required transmission providers to file a single open access tariff that offers network and point-to-point transmission service. In the Western Interconnection, the most relevant type of transmission service is the point-to-point service.[3] The pro forma tariff specifies two types of point-to-point transmission service: firm and non-firm service. Firm service provides a nearly unconditional amount of transmission service to the transmission customer for the specified term. Non-firm transmission service is

[1] Order 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 75 FERC 61,080 (April 24, 1996).

[2] Order 889, Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct , 75 FERC 61,078 (April 24, 1996)

[3] Point-to-Point transmission service is defined as "the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery." Order 888, Appendix D, p. 35.

reserved and scheduled on an as-available basis and can be curtailed and interrupted under certain conditions. Non firm transmission service cannot be contracted for longer than one year.

The specific terms and conditions of point-to-point transmission service are set forth in the pro forma tariff in Appendix D of Order 888. Section 13.2 of the pro forma tariff specifies the reservation priority method for the types of point-to-point transmission service as follows:

- Long-term firm point-to-point transmission service shall be available on a first-come, first-served basis, i.e. in the chronological sequence in which each transmission customer has reserved service.

- Firm point-to-point transmission service will always have a reservation priority over non-firm point-to-point transmission service.

- The priority of short-term firm point-to-point transmission service will be conditional based upon the length of requested transaction. If the transmission system becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to specified deadlines in accordance with the term of service.

Under these rules, long-term firm point-to-point transmission service became the desired and only realistic tariff option for developers of new generator projects. Prospective wind developers have explained that in order to obtain financing for their projects, the lending community requires guarantees that the generator will have access to transmission and be able to sell electrical output on a reliable basis over the 20-year term of projects. Non-firm transmission tariffs do not provide sufficient guarantees for renewal over time to justify the initial investment. As a result, long-term firm transmission service has become been the only viable option for most wind generator projects.

Under the pro forma tariff rules of Order 888, long-term firm point-to-point transmission service is allocated on a sequential first-come, first-served basis. Transmission providers have implemented this policy by creating a queue for transmission service. Transmission customers that are already linked to the interconnection can make requests for transmission service. If there is insufficient transmission capacity, the transmission customer will be rationed according to the transmission service queue.

Order 888 did not address the longer term problem of deciding how to process competing generator requests to interconnect with the grid. The issue of generator interconnection procedures has become formalized in recent years with FERC issuance of new interconnection rules governing large and small generators.

Order 2003 and the Generator Interconnection Queue

In July 2003, FERC issued Order 2003 that set forth standardized procedures and agreement terms for large generators seeking interconnection to the transmission grid.[4] Large generators were defined as having a capacity of more than 20 MW. FERC developed a related interconnection policy for smaller generators defined as having a capacity equal to or less than 20 MW.[5] According to FERC, the purpose of standardizing interconnection procedures was to (1) limit the opportunities for transmission providers to favor their own generators, (2) facilitate market entry of generators and promote competition, and (3) encourage investment into the infrastructure of generation and transmission system.[6]

Under Order 2003, the procedure and rules governing the interconnection of large generators are provided in Appendix C, the Standard Large Generator Interconnection Procedures (LGIP). The key steps to enable a generator to interconnect are summarized below.

- The generator initially submits an interconnection request to the transmission provider. The request must include preliminary site documentation, the expected in-service date, and a $10,000 deposit.

- After receiving a complete interconnection request, the transmission provider puts the request in its interconnection queue and assigns it a queue position. The queue position is based on the date and time of its receipt. The queue position determines the (i) order that the transmission provider performs interconnection studies and (ii) the assignment of costs responsibility for installing facilities to make the interconnection.

- A scoping meeting is held between the transmission provider and generator to discuss potential points of interconnection and technical information.

- The generator enters into agreements with the transmission provider to perform a series of interconnection studies[7] to be performed by the transmission provider in sequential order.

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[4] Order No. 2003, Standardization of Generator Interconnection Agreements and Procedures, 104 FERC 61,103, (July 24, 2003). Subsequent related orders include: Order No. 2003-A, 106 FERC 61,220 (March 5, 2004); Order No. 2003-B, 109 FERC 61,287 (December 20, 2004); Order No. 2003-C, 111 FERC 61,401 (June 16, 2005).

[5] Order No. 2006, Standardization of Small Generator Interconnection Agreements and Procedures, (May 12, 2005).

[6] Order 2003, p. 4.

[7] (1) Interconnection Feasibility Study. A preliminary evaluation of the feasibility of the proposed interconnection. The generator must submit a $10,000 deposit for this study. The transmission provider must complete the study within 45 calendar days after the signing of the interconnection feasibility study agreement.

(2) Interconnection System Impact Study. A comprehensive analysis of the impact of the proposed interconnection on the reliability on the transmission provider's system and affected systems. The generator

Interconnection Queue Position Rules

Section 4 of the LGIP provides the rules governing the interconnection queue. (See the Appendix for the terms of LGIP, Section 4). The general principles for a sequential first come, first served approach are specified in section 4.1. The queue position for an interconnection request is determined by the date and time of filing the request relative to other applicants. A higher queued request is one that is placed earlier in the queue relative to a request filed later and placed lower in the queue. The queue position determines the order of performing the interconnection studies and the cost responsibility for the facilities needed for the interconnection.

Section 4.2 provides an exception to first come, first served principle. The clustering option allows the transmission provider discretion to study and pursue multiple requests in a common group. If the transmission provider elects to study requests in a cluster, it may take all requests over a period up to 180 calendar days (the "Queue Cluster Window") and study them together without regard to the underlying interconnection service. The transmission provider has additional discretion to set deadlines for interconnection studies as provided for rules governing affected systems in section 7.4.

FERC envisioned clustering as a flexible alternative to facilitate coordinating interconnection requests with transmission planning. In discussing comments about clustering in Order 2003, FERC issued the following statements:

> Clustering is strongly encouraged in queue management and the Interconnection Study process for all Transmission Providers. We vigorously support the use of queue windows to manage the Interconnection Study process. . . Clustering (by queue position and electrical location) ensures that the regional expansion plan considers all uses of the Transmission System and enables expansion of the system to be accomplished in the most efficient manner reasonably achievable.[8]

Section 4.3 imposes restrictive constraints on the transferability of the queue position. A generator with a queue position may transfer its queue position to another party only if

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must provide the transmission provider with a $50,000 deposit. The transmission provider has 60 calendar days to complete the study after signing the agreement to perform the study.

(3) Interconnection Facilities Study. This study identifies the facilities necessary to complete the interconnection, the cost of those facilities, and the time to interconnect the generator. The generator must submit a $100,000 deposit or monthly payments to the transmission provider.

(4) Optional Interconnection Study. This study or sensitivity analysis examines the assumptions specified by the generator to identify possible network upgrades that may be required to transmission service. The generator must provide the transmission provider with a $10,000 deposit.

[8] Order 2003, p. 37-38.

that party acquires the specific generating facility linked to the interconnection request and the point of interconnection does not change.

FERC apparently decided against structuring the queue position with property right qualities that would have permitted parties to buy and sell their queue positions in market transactions. FERC sided with commentators who worried that queue trading would unnecessarily increase the complexity of analyzing interconnection requests because of changing assumptions and the potential for adverse gaming opportunities.[9]

Section 4.4 provides the conditions under which the generator may obtain modifications to the interconnection request without loosing its queue position. These provisions attempt to strike a balance between allowing minor modifications to bump requests out of the queue, but also not burdening the transmission provider with significant changes that could lead to expensive revisions in preparing interconnection studies.

Small Generator Interconnection

Recently in May 2005, FERC issued Order No. 2006 which provides new standardized interconnection procedures for small generators. Small generators are defined as having a capacity of 20 MW or less. Small generator interconnection requests generally impose a smaller burden on transmission providers and can often be completed in a shorter time period than larger generators. Representatives from small generator groups had urged FERC to adopt a separate interconnection queue for small generators and large generators. Small generators hoped to avoid the entanglement of the longer study times associated with requests by large generators. FERC rejected this approach on grounds that a two queue approach would delay and complicate the process for transmission providers and that small generator requests may still move through the study process at a faster speed once the study process begins.[10]

Codes of Conduct

FERC issued Order No. 2004 to establish uniform standards of conduct to prevent transmission providers from giving undue preferences to their energy affiliates and ensure transmission is provided on a non-discriminatory basis.[11] The standards of conduct in Order 2004 are consistent with FERC's desire to functionally separate the transmission services from other aspects of integrated utilities and also tightened the earlier standards of conduct created in Order 889.

Under Order 2004, an integrated utility must create tighter firewalls between employees in the transmission division and employees in other divisions and with energy affiliates. In particular, Section 358.5 requires that transmission providers limit access of

[9] Order 2003, p. 38-39.
[10] Order No. 2006, p. 52-53.
[11] Order No. 2004, Standards of Conduct for Transmission Providers, 105 FERC 61,248 (November 25, 2003).

information and communications to other employees to information that is available on the OASIS system.

While the objective is to limit the danger of undue preferences and discrimination, there is a corollary loss of communication and coordination that would otherwise occur between transmission employees and other employees. This problem is most acute for the coordination among employees in the planning division and the experts in transmission planning, and effectively restricts their joint participation in regional and sub-regional transmission planning efforts as discussed below.

2. Interaction of Queuing with State Policies, LSE Resource Plans, and Transmission Planning

Over the past five years, three important initiatives have been influencing the future direction of electricity markets in the Western Interconnection. First, state policy makers have supported greater use of renewable energy and enacted numerous renewable portfolio standards (RPS) in many states. Second, Western utilities have been engaged in a new wave of resource planning and increasingly identifying wind as an economical generating resource. Third, there has also been an explosion of pro-active transmission planning at both the interconnection-wide level and the sub-regional planning level. These three drivers would suggest a future path that increases the use of renewable energy and develops new transmission expansion in a coordinated fashion with new generation additions.

Current queuing policies designed to promote open access transmission, however, may inadvertently slow down or possibly short-circuit these policy and planning efforts in the West. The rigidity of the queuing rules could effectively undermine and derail the implementation of the best made plans and policies.

State Policies Promoting Renewable Energy

In the West, there is a growing movement by individual states to enact goals and requirements to increase the use of renewable energy for in-state electric generation. As of June 2005, six of the eleven states in the Western Interconnection have adopted RPS policies: Arizona (1.1% by 2007, 60% from solar); California (20% by 2010); Colorado (10% by 2015 with 4% from solar); Montana (15% by 2015); Nevada [UPDATE] (20% by 2015, 6% from energy efficiency); and New Mexico (10% by 2011).[12] In the broader region of the 18 states of the Western Governors' Association (WGA), 8 states have RPS requirements including the six identified above and Hawaii (20% by 2020) and Texas (2.7% by 2009).

In June 2004, the WGA Governors adopted a resolution calling for expanded use of clean and diversified energy resources with the goal of adding 30,000 MW of "clean" energy

[12] Wiser, p. 7. See also the state clean energy map on the website of the Union of Concerned Scientists, http://www.ucsusa.org/clean_energy/renewable_energy/page.cfm?pageID=895.

generating capacity in the 18-state WGA region by 2015.[13] The WGA initiative considers "clean" energy to include traditional renewable energy resources (wind, solar, biomass, and geothermal) and also natural gas and unspecified clean coal technologies. The Western Governors have formed an advisory committee to develop recommendations on how to implement and attain this goal.[14]

The current level of state RPS policies and the WGA clean energy initiative reflects a growing public concern and political will to stimulate greater use of renewable energy in the electric markets.

LSE Resource Planning

Since the 2000-2001 Western electricity crisis, there has been a revival of load-serving entity (LSE) resource planning in the Western Interconnection. State-mandated utility integrated resource plans[15] (IRPs) now cover approximately half of the total load in the eleven Western states in the Western Interconnection.[16] These IRP plans provide insight about the analysis and optimizing decisions that western utilities are pursuing over the next decade.

A forthcoming report by Ryan Wiser of the Lawrence Berkeley Laboratory examines how twelve western utility IRP plans are evaluating renewable resources relative to conventional fuels like natural gas and coal.[17] The LBL analysis finds a growing trend that these utilities are accounting for the risk of high and volatile natural gas prices and the risk of future environmental costs associated with carbon emissions. These combined risks have prompted many western utilities to increase the use of renewable energy in their preferred portfolio of generation resources.

The LBL study found that eight of the twelve utilities included renewable energy in their IRP plans based on economics and risk analysis, and not related to a state mandated RPS requirement. The total contribution of IRP planned renewable energy capacity additions not related to RPS requirements amounts to over 3,500 MW by 2014. The corresponding amount of RPS-driven renewable energy capacity additions in 2014 is about 4,800 MW.

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[13] Western Governors' Association, WGA Policy Resolution 04-14, Clean and Diversified Energy Initiative for the West, June 22, 2004. http://www.westgov.org/wga/policy/04/clean-energy.pdf.

[14] Clean and Diversified Energy Advisory Committee, http://www.westgov.org/wga/initiatives/cdeac/index.htm

[15] The term "integrated resource plan" (IRP) is used here to refer to long-term planning documents prepared by LSEs and reviewed by state regulators. Colorado uses the term "least cost plans." Arizona and New Mexico have not required utilities to perform IRPs, but the New Mexico legislature recently adopted an IRP requirement.

[16] Wiser, Ryan, "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans, Lawrence Berkeley National Laboratory, May 2005 (forthcoming), p. 3. The eleven Western states are Arizona, California, Colorado, Idaho, Montana, New Mexico, Nevada, Oregon, Utah, Washington and Wyoming.

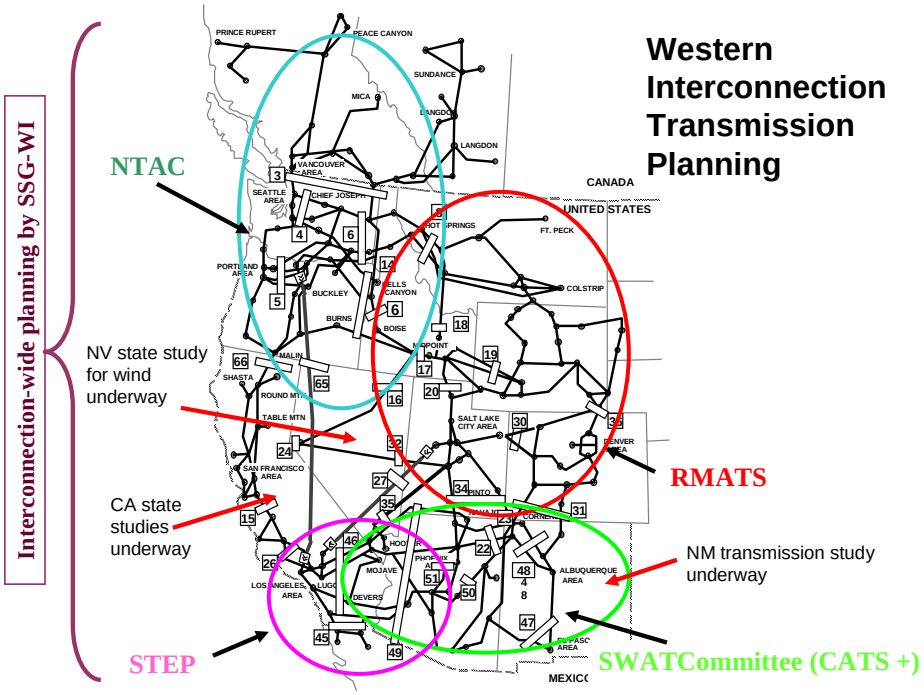
[17] Wiser, p. 3. The 12 utilities are Avista, Idaho Power, Nevada Power, NorthWestern Energy, PacifiCorp, Pacific Gas & Electric, Portland General Electric, Public Service of Colorado, Puget Sound Energy, San Diego Gas & Electric, Sierra Pacific, and Southern California Edison.

The combined renewable energy capacity additions in these IRP analyses, RPS-driven and non-RPS driven, totals to over 8,000 MW by 2014.

These findings indicate that both state policies and utility-based IRP analysis are drivers behind greater use of renewable energy in the West.

Transmission Planning

Beginning in 2001, Western Governors and others have been pressing for open, pro-active, interconnection-wide transmission planning. Previously, transmission planning was typically initiated by a company announcing they planned to build a transmission line. Today pro-active transmission planning is being done on an interconnection-wide basis by the Seams Steering Committee-Western Interconnection (SSG-WI)[18]. Additionally there are numerous sub-regional transmission planning efforts that focus on a smaller geographic areas including the Southwest Transmission Expansion Plan (STEP),[19] the Northwest Transmission Assessment Committee (NTAC),[20] the Rocky Mountain Area Transmission Study (RMATS),[21] and the Southwest Area Transmission study (SWAT).[22] There are also three state-level planning efforts in California, Nevada and New Mexico. See map.



The largest uncertainty in transmission expansion planning is the location of new generation. Load growth and the transmission topology can change over the planning

[18] http://www.ssg-wi.com/
[19] http://www1.caiso.com/docs/2002/11/04/2002110417450022131.html
[20] http://www.nwpp.org/ntac/
[21] http://psc.state.wy.us/htdocs/subregional/home.htm
[22] http://www.azpower.org/swat/

period. However, these uncertainties are smaller than the uncertainties associated with the location, size and type of new generation that may be constructed. The ability to develop a plan that coordinates new generation with optimizing transmission expansion requires the modeling of the entire system. The practical experience of these planning efforts also indicates that there is an iterative process between transmission and generation decisions in finding the optimal solution.

The most recently completed transmission plan in the Western Interconnection was done by the Rocky Mountain Area Transmission Study. The experience in the RMATS process in estimating generating resource additions is instructive. RMATS established a Resources Additions Work Group that was charged with postulating the location of new generation in the five-state region (CO, ID, MT, UT, WY). Estimating the location, size and type of new generation is necessary to run production cost models which are useful tools to estimate the economic benefits of adding new transmission. The Resources Additions Work Group was comprised of representatives of IOU and public power transmission owners, coal developers, wind interests, independent power producers, load serving entities, transmission technology companies, and state agencies. The Work Group examined resource additions in three LSE resource plans (Xcel, PacifiCorp, Idaho Power), generation in the interconnection queues of the transmission owners in the RMATS footprint, and other available information on announced projects. RMATS also made inquiries of generation developers to ascertain the status of their proposed projects. The Resource Additions Work Group aggregated generation into coherent groups by fuel types within geographic areas. If it became necessary to reduce generation within a geographic area to better match demand, the forecasted new generation was reduced by a prorate amount and no individual project was eliminated from the generation alternative.

The Resource Additions Work Group developed four generation alternatives that were coupled with specific transmission projects to the year 2013.

Alternative 1 estimated the generation needed to serve load growth in the RMATS region using information in IRPs and adding generation to meet load growth outside of areas covered by IRPs. The IRP plans tended to rely on new gas-fired generation located close to load centers with only minimal new transmission additions. The Alternative 1 generation portfolio produced 3,900 MW of firm energy (785 MW from natural gas, 2,600 MW from coal, and 2,575 MW from wind, nameplate).

Alternative 2 provided the same total energy as Alternative 1, enough to meet load growth in the RMATS region, but utilized a more cost-effective portfolio of generation linked to development of transmission dependent coal and wind resources in the Powder River Basin. Alternative 2 represents a pseudo-regional IRP generation and transmission plan that seeks a least cost solution covering multiple LSE regions. In contrast, Alternative 1 reflects the higher cost approach of individual LSEs pursuing their separate IRP plans in isolation from the other LSEs in the region that limited generation and transmission options to meet the company's load growth. Alternative 2 coordinated new coal and wind generation with three transmission upgrade projects: (1) the Montana system upgrade that would expand transmission capacity to the Northwest; (2) the

Bridger West upgrades from Wyoming to Utah and Idaho; and (3) a Wyoming to Colorado upgrade. Generation in Alternative 2 yielded the same 3,900 MW of firm energy (350 MW from natural gas, 2,959 MW from coal, and 2,955 MW from wind, nameplate).

The next two RMATS alternatives specified export scenarios that built the generation and transmission assumptions of Alternative 2. These two export scenarios tapped coal and wind energy resources that would be exported outside the RMATS region. The potential market for the energy exports was not formally analyzed in RMATS.

Alternative 3 specified 3,900 MW would be exported to the West Coast using two new 500 kV transmission lines. The RMATS proposal contemplated five possible transmission paths that would connect wind and coal resources in Montana and Wyoming to California, Oregon and Washington. Generation in Alternative 3 would produce 7,800 MW of firm energy (660 MW from gas, 6,149 MW from coal, and 4,955 MW from wind, nameplate). Thirty-nine hundred of the 7,800 MW would be exported. Alternative 4 builds upon Alternative 3 and exports 7,800 MW of energy to the West Coast. The total generation output in Alternative 4 consisted of 11,700 MW of firm energy (1,053 MW from gas, 8,559 MW from coal, and 10,440 MW from wind, nameplate).

The lessons from RMATS are being applied to a larger and more ambitious planning effort of the entire Western Interconnection by SSG-WI. In 2003, SSG-WI produced a report that evaluated generation resources and transmission expansion opportunities under three "bookend" scenarios that emphasized three divergent future generation paths relying on natural gas, coal, and renewable energy, respectively. The current SSG-WI modeling effort underway in 2005 seeks to develop a "realistic" base case and incorporate alternative policies including attainment of state RPS targets and the WGA initiative to add 30,000 MW of clean energy capacity to the WGA states.

The important lesson from this RMATS, SSG-WI and other transmission planning efforts is the need to coordinate new transmission development with a least cost portfolio of generation resources. Certain resources like wind and coal are very dependent upon the future transmission expansion. Planned transmission expansion to targeted resource rich regions is important in developing least cost regional solutions to meeting western demand for electricity.

Queue Problems May Undermine Western RPS Policies and Transmission Planning

Regional planning efforts can formulate the most efficient portfolio of generation and transmission to meet loads. States can enact aggressive RPS policies. These plans and policies may never yield tangible results if there are problems at the implementation stage. Implementation means that generation developers are able to execute contracts and put concrete and steel on the ground to construct new electrical facilities. Bottlenecks at the queue could slow or even undermine Western RPS policies and transmission planning efforts.

Economic principles suggest that the existence of queue lines provides evidence that the demand for generator interconnection services exceeds the quantity supplied by transmission owners. Western transmission owners have experienced and continue to experience significant backlogs of interconnection requests.[23] Observers of electric markets have pointed to numerous factors associated with interconnection queue rules and the characteristics of this industry that contribute to an inflated disparity between viable generator projects and the rate of processing interconnection studies.

First, the interconnection queue contains a certain percentage of "zombie" projects. That is, projects that have no viable economic future but continue to remain officially listed in the queue because there are inadequate signals and incentives in the process to be removed from the queue. Many transmission providers have adopted milestone requirements that require project developers to complete key steps and make commitments that demonstrate the project is active and moving forward.[24]

Second, changed circumstances and revised assumptions can force a transmission provider to repeat the same interconnection study for a given project. New information that certain projects will not be carried out can alter the assumptions about anticipated transmission constraints or flows impacting another project. This re-study problem wastes resources devoted to the earlier studies and slows the progress towards projects further down the queue. To the extent that the queue for interconnection requests fluctuate with a large increases of new requests or sudden large withdrawals of projects from the queue, transmission providers will have a difficult time conducting interconnection studies that do not become obsolete with changed assumptions.[25]

Third, a lack of coordination in the procurement process can artificially inflate the interconnection queue for limited periods and distort the resources devoted to interconnection studies. In one example, a transmission provider operating within the Southwest Power Pool in a control area with a peak load just over 4,000 MW, received 15 interconnection requests in a short period that totaled over 5,760 MW. Of the pending requests, 5000 MWs consisted of wind energy projects and 92 percent of the proposed wind projects were in the same geographical region.[26] This particular surge of interconnection requests by wind developers was prompted by a utility issuing a request for proposal (RFP) for a designated wind project. Numerous wind developers vying for the RFP submitted interconnection requests as part of their efforts to win the pending proposal. Better coordination between the utility issuing an RFP and the transmission provider evaluating interconnect requests would improve the efficiency of managing the queue.

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[23] See selected transmission provider queue lists: Bonneville Power Administration, http://www.transmission.bpa.gov/Business/Reserve_and_Schedule_Transmission/girequests.cfm ; PacifiCorp, http://www.oasis.pacificorp.com/oasis/ppw/lgia/pacificorplgiaq.htm
California ISO, http://www1.caiso.com/thegrid/planning/geninterconnect/isointconqueue.html

[24] Transcript, FERC Technical Conference on the Queue for Interconnection Requests, January 21, 2003 (Queuing Conference). See comments by Steve Herling of PJM, pg. 10-12; Bruce Rew of Southwest Power Pool, pg. 27-28.

[25] Queuing Conference, See comments by Wes Williams of Southern California Edison, pg. 82-84.

[26] Queuing Conference, See comments by Don Jones of Xcel Energy, pg. 80-81.

Fourth, the existence of a large interconnection queue suggests that transmission providers do not provide enough resources in terms of personnel to process interconnection requests. Transmission providers are typically regulated monopolists that do not face the same incentives characteristic of a competitive market. For example, transmission providers do not risk losing market shares by failing to respond to excess demand for their services. And even though generators pay for interconnection studies performed by transmission providers, the price for performing this service does not increase or decrease with the change in demand for the service. As a result, the transmission providers do not have a strong incentive to devote more resources to better match the fluctuations in demand for interconnection requests.[27]

Fifth, the sequential queue study process promotes a reactive approach to transmission expansion that leads to inefficient and sub-optimum results. Unless there is a coordinated pro-active transmission planning process, the transmission operator's decision to add transmission is largely influenced by incremental requests for upgrades to accommodate individual generator projects. This is particularly relevant for wind energy since good wind resources are often located in concentrated regions that should be connected to the grid with capacity levels that reflects the forward looking future development in the region.

Sixth, the wind industry has been subjected to substantial cyclical fluctuations that can overwhelm the interconnection requests to transmission markets. A key driver for these cyclical fluctuations is driven by the Production Tax Credit (PTC). Under present law, the PTC provides a federal tax credit of 1.5 cents/kilowatt-hour (adjusted annually for inflation since 1992) for the production of electricity from qualified wind energy facilities. The current value of the PTC is 1.9 cents/kilowatt-hour of electricity produced. The credit was originally enacted in the Energy Policy Act of 1992 and applied to electricity produced by a qualified wind facility placed in service after December 31, 1992. Congress had extended the end date of the PTC several times in recent years and it is currently scheduled to expire January 1, 2006.

Unfortunately, the stop and start nature of the PTC has undercut some of the intended benefits of the incentive. Four to six months before the tax credit expires, financial lenders hesitate in providing capital for wind projects because of the uncertainty created by the impending expiration of the credit. A rush to complete projects before the deadline leads to added costs resulting in higher electricity prices per kilowatt-hour. Orders languish during period when the PTC is not in effect as customers hold off new purchases until the PTC is renewed.[28] The stop and start nature of the PTC also introduces uncertainty for utilities evaluating wind generation options as part of their resource plans.

[27] Queuing Conference, See discussion by transmission providers regarding limited staffing resources and use of consultants to meet fluctuations in interconnection requests, pg. 48-55.
[28] Queuing Conference, See comments by Dave Cory of PacifiCorp, 8, 63-63.

3. Potential Solutions

This paper identifies four areas where improvements in policies related to queuing. Some of the suggestions are reflected in recent FERC interconnection rules.

- *Give preferential treatment in the queuing process to those generating projects that have been selected pursuant to transparent, state-approved resource plans and related Requests for Proposals*.

Existing interconnection queue policy relies on a sequential first-come, first-served that eliminates transmission provider discretion in selecting projects. The purpose for removing discretion is to eliminate the possibility of undue discrimination in the interconnection process in favor of the transmission provider's generation projects or against competing projects. The emphasis on non-discriminatory interconnection decision making reflects our historic belief in a legal system that relies on unbiased judges and juries to ensure the justice remains blind. But in generator interconnection decision making, imposing the blindfold of restrictive sequential first come, first serve rules effectively ignores important information and leads to inefficient solutions and a sub-optimal expansion of the transmission system.

A preferred option would be to incorporate flexibility around the existing queue and move forward projects that have been selected by a recognized transparent, state-approved resource planning process and/or a related RPF process for expedited interconnection review. The idea is to remove the danger of undue discrimination while utilizing the available information that guides good economic and technical decision making.

The intent of this proposal is to incorporate the lessons of the RMATS and SSG-WI processes that pro-active regional planning can identify efficient portfolios of generation and transmission projects. The critical aspect of implementing this type of queue extraction mechanism is to create a reliable, transparent and respected institutional process that would provide an insightful decision making process free of undue discriminatory motives. This requires an open and inclusive process with transparency about data and methods. The specific requirements could be left to the discretion of state regulatory institutions.

- *Expand the use of the open season process as an alternative to FERC's first-come-first-served queue rules and as an extension of the clustering option.*

The open season process provides one alternative to the sequential queue process. The open season has been used for years in the natural gas industry to identify the demand for new pipeline capacity. FERC policy embraces the use of the open season method in the natural gas industry. The application of an open season process for transmission would involve the following steps. A transmission provider announces that it will be holding an open season where potential customers would indicate their interest in obtaining transmission services. At some point in the process, the transmission provider would

provide detailed plans for a proposed expansion and solicit bids for reserving future transmission rights. Potential customers would then respond by submitting bids backed by financial commitments. The resulting bid response for the proposed project would give the transmission provider certainty about the level of demand for the project and a pool of funds to proceed with the project. In effect, the open season process provides a pseudo-market mechanism to reveal the demand for transmission services to the transmission provider in an open and non-discriminatory manner.

The open season process entails more that what current FERC rules provide in the clustering of interconnection requests. Clustering gives the transmission provider the discretion to study a group of interconnection requests submitted over a 180 day period. Individual requests are grouped and evaluated in a common batch. Clustering does not include, however, other important features of an open season process such as the transmission provider plans for a specific transmission project and the solicitation of bids for rights to transmission services. The open season process encourages pro-active planning to anticipate the demand for transmission services and provides a mechanism to test the market demand for such services before the transmission provider is financially committed to pursue the project.

Two recent examples of transmission providers utilizing an open season process provide a role model for the rest of the transmission industry. The first is NorthWestern Energy's open season project for a proposed transmission expansion of between Montana and eastern Idaho known as WECC Path 18.[29] The second is Bonneville Power Administration's open season for a 500 kV line expansion to the McNary-John Day line.[30] These specific examples may or may not move towards implementation of the proposed transmission expansion. It does illustrate, however, how the process can work within the context of the electricity market and existing FERC regulations.

- *Encourage transmission providers to group interconnection requests and transmission service requests to identify cost effective investments. Southern California Edison's proposal for a renewable trunk line proposal in the Tehachapi region in California provides a role model to identify transmission investments in advance of future generation requests.*

Wind energy is closely linked to the development of new transmission. Transmission expansion, however, has been plagued by a problem referred to as the chicken and egg dilemma. Transmission owners are reluctant to build new transmission lines without commitments from generators, and conversely, generation developers are reluctant to build new generation resources without access to transmission.

The transmission problem for wind energy is exacerbated by a geographic and timing mis-match. Wind resources tend to be located in remote rural areas that are far from load centers. Since wind generators need to be located near wind resources, wind energy is dependent upon significant new transmission investments to deliver the energy to loads.

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[29] http://www.oatioasis.com/NWMT/index.html

[30] http://www.transmission.bpa.gov/PlanProj/Transmission_Projects/mcnary/mjdosi.cfm

The timing issue arises from divergent time horizons between wind and transmission development. Wind developers can generally permit and construct a wind generation project in two years or less. New transmission projects can take about 5 to 8 years to build.

The Southern California Edison's (SCE) renewable trunkline proposal for the Tehachapi/Antelope transmission project provides a solution to the problem of getting transmission built to wind resource regions in advance of wind projects. The Tehachapi region could provide 4,600 MW of wind energy at full development. The renewable trunkline concept provides a practical solution to the "chicken and egg" problem, and avoids the pitfall of inefficient piecemeal studies required under current interconnection rules. This proposal removes key impediments that discourage transmission investments to remote wind resource regions. The proposed changes would encourage phased-in transmission investments based on the predictable growth of many independent wind generation projects in a designated concentrated area.

The specific elements of the SCE proposal include the following features.

- An exception to FERC's cost recovery rules for generation tie lines necessary to meet the public interest represented by a state's load-based renewable resource portfolio standard. The SCE proposal would interconnect a geographically limited renewable resource region, without siting flexibility, located a reasonable distance from the grid.

- Rolled-in rate treatment for transmission project costs that integrate large concentrations of potential renewable generation resources. Under current FERC policy, established rules require participant (generator) funding of transmission projects connecting specific generators (i.e. generation-tie lines).

- Grant cost recovery for prudent costs based on reasonable forecasts of potential renewable generation without formal interconnection agreements or contracts to loads.

- Grant cost recovery for prudent costs even if the transmission project is cancelled or abandoned because there is insufficient generation development in the region or necessary regulatory approvals are not granted. Under current policy, FERC will disallow 50% of the investment of an abandoned or cancelled project.

FERC should approve the renewable trunkline proposal and encourage other transmission providers to use this approach to tap wind energy in other areas. For example, regionally concentrated high-value wind resources are located in eastern New Mexico (4,000 MW), Wyoming (5,000 MW), and along the Columbia River on the Oregon and Washington border (4,400 MW). The renewable trunkline concept may be a useful tool to encourage development of these potential sources of wind energy.

- *Consider modifications to FERC rules that would allow the transmission and resource planning functions of vertically integrated utilities to discuss transmission needs associated with new generation being considered to serve the utility's load. Such modifications would allow such communication provided it is transparent to outside parties and part of a state-approved resource planning and acquisition process.*

Under current FERC rules for codes of conduct applicable to electric utilities, transmission division employees cannot communicate or share information with the planning division employees of the same utility unless that information is publicly available and posted on the utility's OASIS website. The intent of the codes of conduct is to prevent an exchange of information within the utility that would lead to discriminatory actions by the transmission provider or preferential treatment to its own generation interests. These restrictions, however, potentially undermine efforts to encourage pro-active regional and sub-regional transmission planning efforts.

The existing Western transmission planning efforts exemplified by SSG-WI and RMATS involve open forums with inclusive participation by relevant stakeholders. It is ironic that employees with expertise in transmission and planning from the same utility cannot participate or communicate in the same open forum due to restrictive standards of conduct provisions. FERC has explicitly encouraged Western transmission planning efforts. It should seek to find a way to provide reasonable flexibility in the codes of conduct rules to permit staff from transmission and planning in a common integrated utility to fully participate in these forums.

Conclusion

While FERC policies on queuing for interconnection and transmission service ensure fair methods for allocating scarce transmission resources, these policies impose constraints on state efforts to promote RPS goals, and implement LSE resource plans and regional transmission planning efforts. These constraints may particularly hinder policy efforts to encourage more wind development.

This paper recommends a close consideration of the following four remedies:

- Give preferential treatment in queuing processes to those generating projects that have been selected pursuant to transparent, state-approved resource plans and related Requests for Proposals.

- Expand the use of the open season process as an alternative to FERC's first-come-first-served queue rules and as an extension of the clustering option.

- Encourage transmission providers to group interconnection requests and transmission service requests to identify cost effective investments. The renewable trunk line proposal is a good role model to encourage transmission expansion for wind development

- Consider modifications to FERC rules that would allow the transmission and resource planning functions of vertically-integrated utilities to discuss transmission needs associated with new generation being considered to serve the utility's load. Rule modifications would allow such communication provided it is transparent to outside parties and part of a state-approved resource planning and acquisition process.

Appendix

Summary of Selected FERC Rules

FERC Order No. 888
Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities
(April 24, 1996)

Appendix D: Pro Forma Open Access Transmission Tariff (Order No. 888-A)

II. Point-To-Point Transmission Service

Section 13.2 Reservation Priority: Long-term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, i.e. in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines; one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. A longer term competing request Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

FERC Order No. 2003-A
Standardization of Generator Interconnection Agreements and Procedures
(March 5, 2004)

Appendix B -- Standard Large Generator Interconnection Procedures (LGIP)

Section 4. Queue Position

4.1 General

Transmission Provider shall assign a Queue Position based on the date and time of receipt of the valid Interconnection Request; provided that, if the sole reason an Interconnection Request is not valid is the lack of required information on the application form, the Interconnection Customer provides such information in accordance with Section 3.3.3, then Transmission Provider shall assign Interconnection Customer a Queue Position based on the date the application form was originally filed. Moving a Point of Interconnection shall result in a lowering of Queue Position if it is deemed a Material Modification under Section 4.4.3.

The Queue Position of each Interconnection Request will be used to determine the order of performing the Interconnection Studies and determination of cost responsibility for the facilities necessary to accommodate the Interconnection Request. A higher queued Interconnection Request is one that has been placed "earlier" in the queue in relation to another Interconnection Request that is lower queued.

Transmission Provider may allocate the cost of the common upgrades for clustered Interconnection Requests without regard to Queue Position.

4.2 Clustering

At Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the Interconnection System Impact Study.

Clustering shall be implemented on the basis of Queue Position. If Transmission Provider elects to study Interconnection Requests using Clustering, all Interconnection Requests received one hundred and eighty (180) Calendar Days, hereinafter referred to as the "Queue Cluster Window" shall be studied together without regard to the nature of the underlying Interconnection Service, whether Energy Resource Interconnection Service or Network Resource Interconnection Service. The deadline for completing all Interconnection System Impact Studies for which an Interconnection Impact Study Agreement has been executed during a Queue Cluster Window shall be in accordance with Section 7.4, for all Interconnection Requests assigned to the same Queue Cluster Window. Transmission Provider may study an Interconnection Request separately to the extent warranted by Good Utility Practice based upon the electrical remoteness of the proposed Large Generating Facility.

Clustering Interconnection System Impact Studies shall be conducted in such a manner to ensure the efficient implementation of the applicable regional transmission expansion plan in light of the Transmission System's capabilities at the time of each study.

The Queue Cluster Window shall have a fixed time interval based on fixed annual opening and closing dates. Any changes to the established Queue Cluster Window interval and opening or closing dates shall be announced with a posting on Transmission Provider's OASIS beginning at least one hundred and eighty (180) Calendar Days in advance of the change and continuing thereafter through the date of the first Queue Cluster Window that is to be modified.

4.3 Transferability of Queue Position.

An Interconnection Customer may transfer its Queue Position to another entity only if such entity acquires the specific Generating Facility identified in the Interconnection Request and the Point of Interconnection does not change.

4.4 Modifications

Interconnection Customer shall submit to Transmission Provider, in writing, modifications to any information provided in the Interconnection Request. Interconnection Customer shall retain its Queue Position if the modifications are in accordance with Sections 4.4.1, 4.4.2 or 4.4.5, or are determined not to be Material Modifications pursuant to Section 4.4.3.

Notwithstanding the above, during the course of the Interconnection Studies, either Interconnection Customer or Transmission Provider may identify changes to the planned interconnection that may improve the costs and benefits (including reliability) of the interconnection, and the ability of the proposed change to accommodate the Interconnection Request. To the extent the identified changes are acceptable to Transmission Provider and Interconnection Customer, such acceptance not to be unreasonably withheld, Transmission Provider shall modify the Point of Interconnection and/or configuration in accordance with such changes and proceed with any re-studies necessary to do so in accordance with Section 6.4, Section 7.6 and Section 8.5 as applicable and Interconnection Customer shall retain its Queue Position.

4.4.1 Prior to the return of the executed Interconnection System Impact Study Agreement to Transmission Provider, modifications permitted under this Section shall include specifically: (a) a decrease of up to 60 percent of electrical output (MW) of the proposed project; (b) modifying the technical parameters associated with the Large Generating Facility technology or the Large Generating Facility step-up transformer impedance characteristics; and (c) modifying the interconnection configuration. For plant increases, the incremental increase in plant output will go to the end of the queue for the purposes of cost allocation and study analysis.

4.4.2 Prior to the return of the executed Interconnection Facility Study Agreement to Transmission Provider, the modifications permitted under this Section shall include specifically: (a) additional 15 percent decrease in electrical output (MW), and (b) Large Generating Facility technical parameters associated with modifications to Large Generating Facility technology and transformer impedances; provided, however, the incremental costs associated with those modifications are the responsibility of the requesting Interconnection Customer.

4.4.3 Prior to making any modification other than those specifically permitted by Sections 4.4.1, 4.4.2, and 4.4.5, Interconnection Customer my first request that Transmission Provider evaluate whether such modification is a Material Modification. In response to Interconnection Customer's request, Transmission Provider shall evaluate the proposed modifications prior to making them and inform the Interconnection Customer in writing whether the modifications would constitute a Material Modification. Any change to the Point of Interconnection, except those deemed acceptable under Sections 4.4.1, 6.1, 7.2 or so allowed elsewhere, shall constitute a Material Modification. Interconnection Customer may then withdraw the proposed modification or proceed with a new Interconnection Request for such modification.

4.4.4 Upon receipt of Interconnection Customer's request for modification permitted under this Section 4.4, Transmission Provider shall commence and perform any necessary additional studies as soon as practicable, but in no event shall Transmission Provider commence such studies later than thirty (30) Calendar Days after receiving notice of Interconnection Customer's request. Any additional studies resulting from such modification shall be done at Interconnection Customer's costs.

4.4.5 Extensions of less than three (3) cumulative years in the Commercial Operation Date of the Large Generating Facility to which the Interconnection Request relates are not material and should be handled through construction sequencing.

FERC Order No. 2006
Standardization of Small Generator Interconnection Agreements and Procedures,
(Issued May 12, 2005)

Appendix E -- Small Generator Interconnection Procedures (SGIP)

1.6 Queue Position
The Transmission Provider shall assign a Queue Position based on the date- and time-stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Transmission Provider shall maintain a single queue per geographic region. At the Transmission Provider's option, Interconnection Requests may be studies serially or in clusters for the purpose of the system impact study.