The Way Forward

Why Transmission Right Sizing and Federal Bridge Financing Hold the Key to Western Renewable Resource Development

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The Way Forward: Why Transmission Right Sizing and Federal Bridge Financing Hold the Key to Western Renewable Resource Development

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Transmission planners have long supported the idea that new transmission projects should be sized to take advantage of economies of scale and to accommodate future growth in use without overbuilding or overspending in the process. More recently, the idea of building transmission to gain economies of scale has transformed to include the notions that transmission infrastructure can be built in ways that minimize cumulative environmental impacts and enable the greatest potential from renewable resources that will offset carbon-emitting energy sources. This transformed concept has been dubbed transmission "right sizing" or as at least one industry leader says, "smart sizing."[1] The concept should be understood to involve sizing high-priority transmission facilities from resource-rich locations to population loads in a quantity sufficient to enable meeting longer-term carbon reduction goals.[2]

Over the past decade, planners and renewable energy project developers alike have demonstrated significant interest in building major new transmission projects in the Western United States, largely in response to policies encouraging development of the nation's renewable energy resource areas. Significant new planning efforts have resulted in a number of proposals to build transmission, including proposals for interstate transmission highways,[3] to access clean energy regions within the West.

Based on our experience dealing with high-voltage transmission matters, the Energy Foundation has asked us to prepare this White Paper to focus on the "right-sizing solution." The paper will explain the concept of right sizing, provide historical context and identify the value of "right sizing" high-priority transmission lines to access renewable resource-rich areas in the West.[4] As part of this discussion, our paper will analyze a key barrier to major new transmission projects—the inadequacy of current financing and cost recovery mechanisms. We review prior

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[1] Patrick Reiten, President of Pacific Power, division of PacifiCorp, in his keynote address at "Expanding and Modernizing the Electric Grid: Developing Essential Infrastructure for the Clean Energy Future," a symposium sponsored by the Energy Futures Coalition, Renewable Northwest Project, and others on July 14, 2010. The concept will be referred to as "right sizing" in this White Paper.

[2] Western states have set the following long-term greenhouse gas reduction goals: Arizona – 50% below 2000 levels by 2040; California – 80% below 1990 levels by 2050; New Mexico – 75% below 2000 levels by 2050; Oregon – >75% below 1990 levels by 2050; Washington – 50% below 1990 levels by 2050. Western Climate Initiative, *Statement of Regional Goal*, at 4, Table 1 (Aug. 22, 2007), *available at* http://www.azclimatechange.gov/download/082207_statement.pdf.

[3] The authors' references to the interstate highway system are not meant to advocate for national transmission planning or a national grid. Rather, the authors view the interstate highway system as a useful analogy when considering the financing of large public works that enable interstate commerce to flourish.

[4] References to "the West" in this White Paper are limited to the synchronous grid of the Western Electricity Coordinating Council.

approaches to financing and cost recovery issues and explain why such approaches have not been successful in promoting major new transmission to access some of the nation's most attractive renewable energy resource areas in the West. We will also discuss whether proposals for federal participation in financing interstate transmission expansion would address the financing and cost recovery problems we have observed. Our emphasis on *interstate* transmission reflects the assumption that significantly reducing green house gas ("GHG") emissions from the electricity sector will require larger renewable energy standards and GHG reduction targets and a robust Western market for renewable energy. Adequate interstate transmission to access remote, high-quality renewable resources is a predicate if the West is to take full advantage of opportunities for GHG reductions. Thus, we suggest the way forward to clean energy future can be advanced by transmission right sizing and federal bridge financing.

SUMMARY OF CONCLUSIONS

- With the exception of transmission lines delivering power from federal hydroelectric projects, transmission facilities in the West have been constructed by individual utilities primarily to meet their own or shared needs, rather than as a coordinated regional grid. The result is a transmission grid that will not adequately support a West-wide market for renewable energy that includes remote, high-quality resources.

- The open access era has to date resulted in only modest transmission expansion in the Western Electricity Coordinating Council ("WECC") area, but has failed to develop a robust West-wide transmission grid and threatens to underutilize limited transmission corridors.

- Transmission development involves substantial financial risk. Neither transmission nor generation developers will commit to pay for major transmission expansions ahead of assured cost recovery.

- Federal financing of the up-front costs of transmission development has resulted in small-scale (and increasingly promising) success in facilitating development of renewable energy projects in the West, *e.g.*, the McNary-John Day transmission project.

- Federal financial risk mitigation mechanisms could allow the federal government to step in, upon request, and assume, or otherwise help mitigate, the up-front cost recovery risk associated with constructing major new transmission projects that are right sized, *i.e.*, projects with uncommitted capacity that would otherwise not be built in the absence of such up-front cost-recovery assurance.

- Ongoing scenario planning work in WECC should identify high-priority transmission expansion projects connecting remote, resource rich areas to load centers, and the those interested in a clean energy future should consider whether the modest funds needed to financially support right sizing those projects are available under the American Recovery and Reinvestment Act of 2009 ("ARRA") or whether federal participation should be otherwise authorized.

- New requirements for interregional planning and cost allocation protocols in Federal Energy Regulatory Commission's ("FERC") June 17, 2010 Notice of Proposed Rulemaking ("NOPR") are promising, but implementation is particularly problematic in areas without regional transmission organizations ("RTOs"), such as the Northwest and Southwest. Even if effective in addressing the cost allocation barrier to development eventually, the time frame and uncertainties related to implementation of such protocols could well stall timely development of the West's most attractive renewable resources for years.

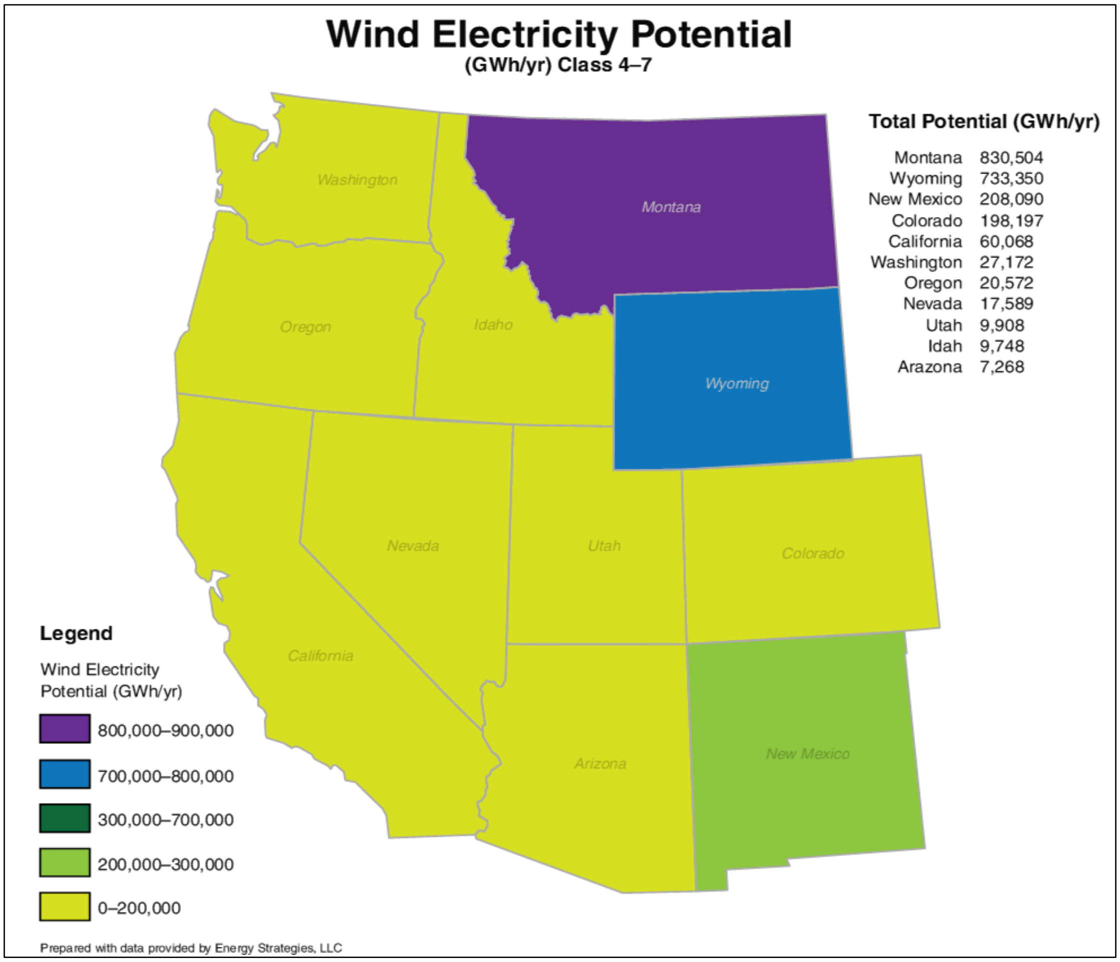
- At this time there are an unprecedented number of transmission projects proposed throughout the West (such as the Mountain States Transmission Intertie, Chinook, Zephyr, and others). The opportunity to identify high-priority projects and build infrastructure to ensure our clean energy future is at hand. Right-sized transmission expansion could be facilitated and expedited if the recovery of investments in transmission capacity in excess of committed generation could be assured.

- Through a relatively low-risk federal financial support program, advocates of a clean energy future could accelerate development of our high-quality, immediately developable renewable resources, enabling the Western states to meet renewable energy and carbon reduction goals that are likely to increase in the future.

INTRODUCTION

If the Western states are to achieve higher renewable energy goals and carbon reductions, the West's transmission infrastructure needs to be expanded to accommodate new sources of renewable energy, some of the most promising of which are located at considerable distance from population centers. Some of the best renewable energy sources are located in the Intermountain West, a prime area that would benefit from interstate transmission highway projects. If we focus on wind resources in the WECC footprint, the most significant potential for higher-capacity factor, utility-scale wind-resource development is located in Montana and Wyoming, up to 1,000+ miles from the West Coast or Southwest regional markets.

Figure 1. Western Wind Energy[5]



The distance from wind resources to load is not the only challenge. While interregional power sales and exchanges have been part of the West's power supply arrangements since at least the 1960s, the WECC transmission system lacks firm transmission capacity for delivery of any meaningful amount of new wind power from Montana and Wyoming to the regional markets serving population centers on the West Coast and Southwest. As an illustration, Figure 2 shows the current major transmission path constraints in the Western system.[6] This map does not depict an efficient interstate system, and will not permit large scale movement of wind energy from the "Saudi Arabia" of wind in the Intermountain West and Northern Plains states to major population centers. The constraints, which are indicated by red lines, effectively isolate almost all of the WECC's best wind resources and significantly limit the development of utility-scale solar for the Southwest or Western regional markets.

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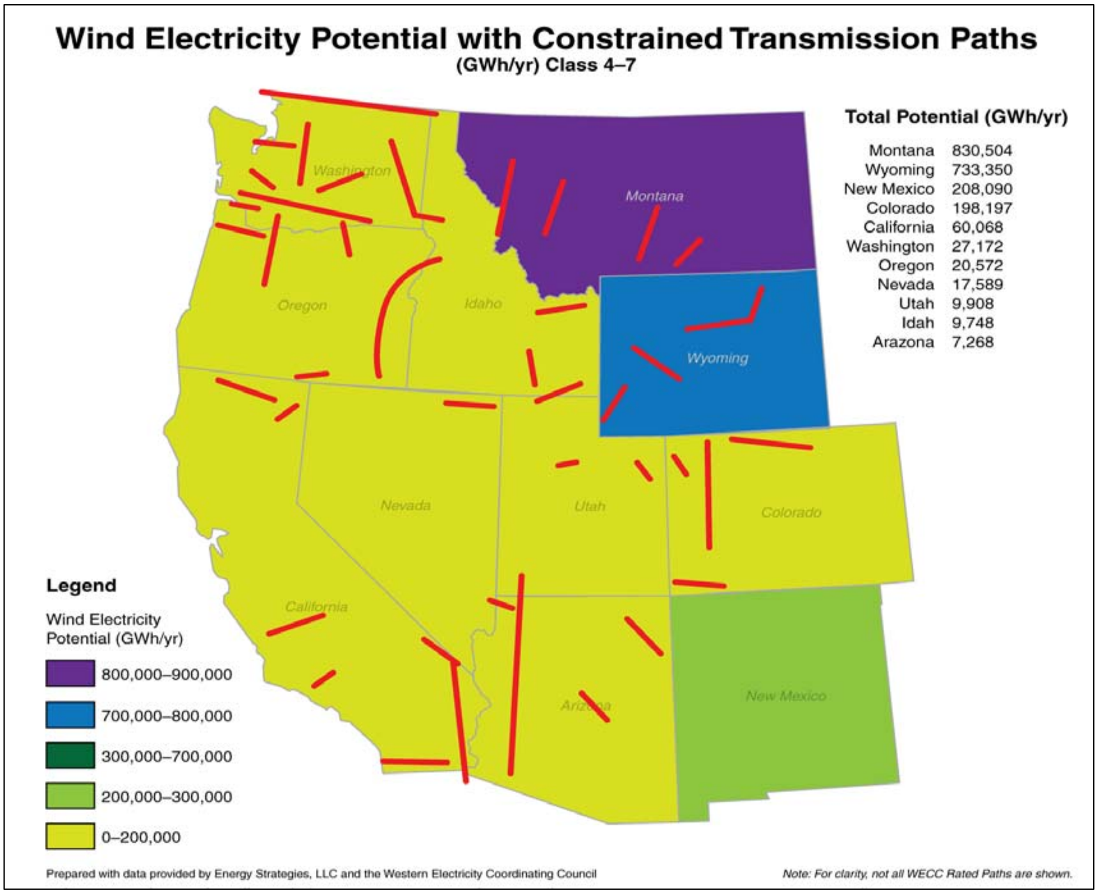
[5] Prepared using information from the Western Governors' Association and U.S. Department of Energy, *Western Renewable Energy Zones – Phase 1 Report*, at 12-13 (June 2009), *available at* http://www.westgov.org/wga/publicat/WREZ09.pdf (cited by U.S. Department of Energy, *National Electric Transmission Congestion Study*, at Fig. 3-3 (Dec. 2009), *available at* http://congestion09.anl.gov/documents/docs/Congestion_Study_2009.pdf (hereinafter "2009 Congestion Study")).

[6] Northwest Power and Conservation Council, *Sixth Northwest Conservation and Electric Power Plan*, at 7-4 (Feb. 2010), *available at* http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan.pdf.

Figure 2. Western Constrained Transmission Paths[7]



The "constraints map" shows only the WECC and therefore does not show the minimal transmission connections between the Western grid and the Eastern grid. As these two grids are not synchronous, they can be tied only by direct current lines, and the existing connecting lines are of relatively low voltage, with very little transfer capability. This lack of connectivity between the two grids blocks delivery of generation from important wind-rich areas to the major Midwest load centers. In addition, it also blocks the types of cross-interconnection exchanges of energy and capacity that could produce greater electric system efficiencies. Increasing interregional transmission with robust direct current ties can provide added benefits that offset the cost increases related to modernizing our electrical grids and integrating new renewable resources. We note that a robust direct current interconnection between the Eastern and Western grids would move Montana and Wyoming resources from a position on the periphery of a Western grid to the center of a national grid. This would also be true for the high-quality resources in the Upper Great Plains. Allowing increased cross-interconnection exchanges could also allow for greater efficiencies in shaping and storing power produced by intermittent resources. More attention ought to be paid to strengthening the ties between the Western and

[7] Prepared using *Western Renewable Energy Zones – Phase 1 Report*, *supra* note 5, at 12-13, and *Sixth Northwest Conservation and Electric Power Plan*, *supra* note 6, at 7-4.

Eastern electrical grids and resolving the attendant technical and political challenges. Transmission planners should undertake studies to examine the costs and benefits of increasing transfer capability between the interconnections to ensure that the benefits of such increased capabilities are not overlooked by focusing on within-interconnection expansion. We therefore recommend further inquiry into increased Eastern and Western grid power transfers, which could constitute a game-changer for the resource-rich West and its growing population.

TRANSMISSION RIGHT SIZING

Right sizing refers to building transmission facilities having greater power transfer capacity than short-term generator interconnection and market conditions require in order to allow for planned growth—in this case the growth in the percentage of clean generation resources in load-serving entities' portfolios—and necessary retirements of fossil fuels. Right sizing takes advantage of economic, environmental, and social efficiencies by capturing economies of scale in siting, permitting, construction, and (potentially) financing. Without right sizing, developers, utilities, regulators, and the public will be faced with incrementally increasing transmission capacity in the near future as demand for renewable resources grows (and will pay the concomitant costs of an inefficient expansion plan), or stalling efforts to access our most attractive renewable resources.

Expansion of transmission is always "lumpy" because of the difficulty of matching transmission capacity to projected demand and projected generation development. The risk of undersizing transmission outweighs the risk of oversizing it, so regulators approved transmission facilities having somewhat larger capacity than required to meet immediate needs. Some of the risk was minimized in the past by building transmission to deliver the output of large hydro-electric and coal plants as these large generation plants were developed. This has served the West well for several decades. In fact, we are only now utilizing—very cost effectively—oversized transmission facilities that were built around the West from the 1960s through the 1980s.

But with the advent of natural gas and renewable energy resources, plant size is variable and often much smaller. For example, wind projects are often built in increments of 100 MW. A 100 MW generating plant may require a 115 kV line at a minimum for reliability, but the capacity of that line will be greater than is needed for the 100 MW plant. Where resources are distant from load—whether a hundred miles or a thousand miles—planners recommend higher voltage, long-distance lines, which have much higher capacity. The discussion about right sizing is largely focused on proposals for such major transmission projects and this notion goes beyond the simple recognition that transmission is built in lumpy increments and contemplates building transmission for an appropriate planning horizon that takes carbon reduction goals into account where doing so will capture economies of scale and the attendant efficiencies, while reducing the environmental impacts to the extent practicable.

Right sizing transmission makes the most efficient use of limited transmission corridors by minimizing the cumulative effect of developing transmission through sensitive lands. In addition, right sizing makes the best use of those transmission corridors that are often the most expensive and contentious, *i.e.*, those passing through urban areas. Some environmentalists support state and federal land use policies that expressly limit the number of transmission corridors or exclude certain lands from consideration or use as corridors. This approach might well drive consideration of right sizing and help build support for sharing the costs of excess capacity for future use through federal support or other broad-based allocation schemes such as the one FERC recently approved for the Southwest Power Pool.[8] However, it could also result in limiting access to remote resources and therefore reduce the West's ability to maximize carbon reduction in the electricity sector. Transmission right-sizing policies thus should be considered even absent new land use policies and, if existing or new transmission corridors are right sized, new regulations limiting transmission corridors may be less necessary.

The capacity gains and right-of-way efficiency of higher voltage lines is striking. For purposes of comparison, while a 345 kV line is capable of transmitting about 400 MW, a 765 kV line carries approximately 2,400 MW. Thus, it would take six 345 kV lines to provide capacity equivalent to that of a 765 kV line.[9] Further, a *single* 345 kV line generally requires a 150-foot right-of-way; a 765 kV line requires only 200 feet.[10] Figure 3 below shows the relative right-of-way requirements between 345 kV and 765 kV lines. A 765 kV line therefore requires a smaller right-of-way than multiple lower-voltage lines needed to carry the same capacity, needs fewer transmission towers (*i.e.*, less construction), and requires fewer reentries onto sensitive lands for subsequent transmission upgrades. Right sizing thus results in a lesser cumulative environmental impact.

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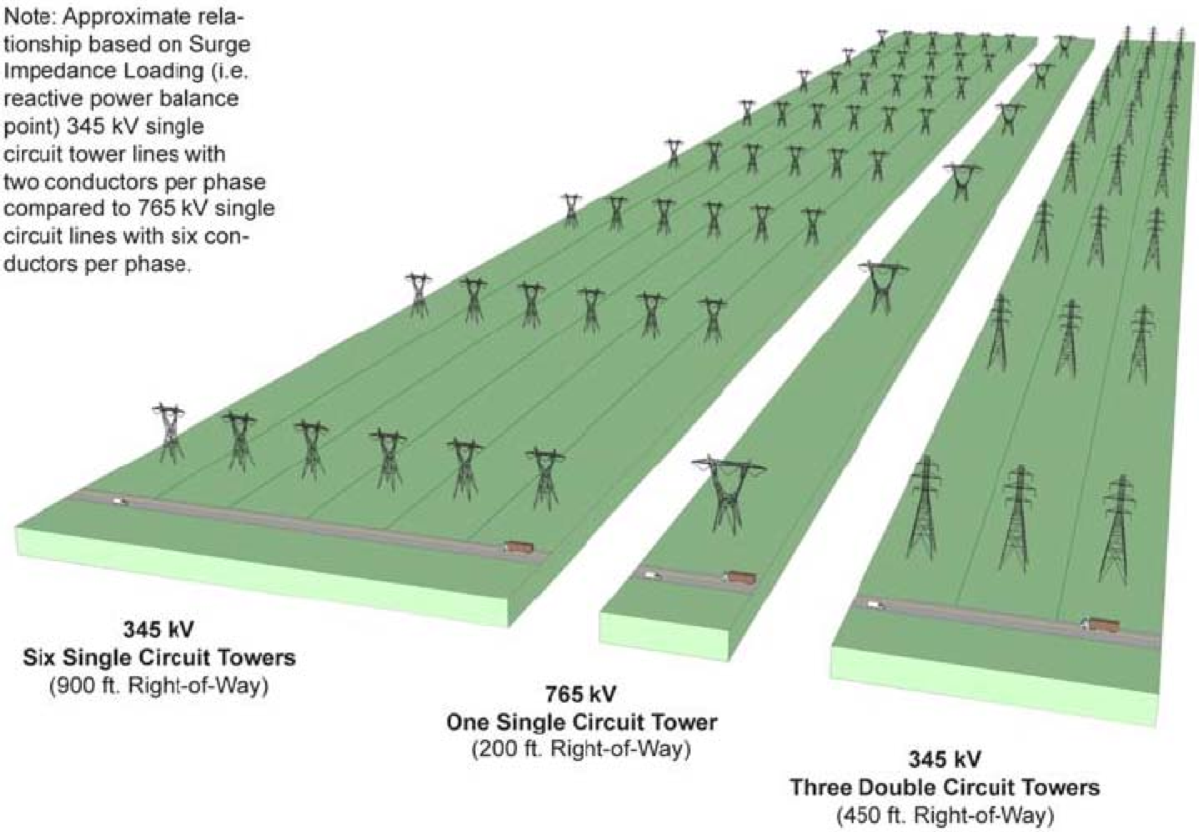
[8] In June 2010, FERC approved the Southwest Power Pool's ("SPP") "highway/byway" approach to cost allocation, which will spread the cost of new transmission projects 345 kV and above to all loads in the RTO, holding that the broad-based cost allocation was just and reasonable given the widespread benefits to the RTO region of new high-voltage transmission. *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252 (June 17, 2010). FERC issued the June 17 NOPR on cost allocation contemporaneously.

[9] American Electric Power, *Looking Towards the Future: Right-of-Way Stewardship*, *available at* http://www.aep.com/about/i765project/docs/LookingTowardstheFuture.pdf.

[10] *Id.*

Figure 3. Right-of-Way Requirements[11]



The authors are aware that the Western transmission system is a 500 kV system, and the use of 765 kV in Figure 3 is primarily to illustrate the relative benefits of using higher voltages. There remain technical and administrative issues in adding 765 kV circuits to the Western grid. David Olsen, Managing Director of the Western Grid Group, notes that planners typically mention potential short circuit problems that may occur at high elevation substations due to lower air densities, and the need to recalculate N-1 contingencies and reset remedial action scheme set points as reasons for maintaining 500 kV lines as the backbone of the Western grid. Olsen suggests strong leadership could overcome such obstacles if there were more agreement that right sizing was appropriate and the capacity of 765 kV line(s) justified. He also notes strong leadership is needed to forge more agreement that the benefits both of right sizing and of 765 kV path ratings outweigh the risks of such future-oriented planning approaches.[12]

Right sizing transmission also offers benefits in terms of reliability. Right sizing transmission may lower the risk of outages due to tree-caused power interruptions and environmental damage due from resulting fires. The incidence of tree-caused incidents with transmission lines is higher for lines 230 kV and below than for higher voltage lines. This appears to result not only from the higher number of miles of 230 kV lines in many regions, but

[11] *Id.*

[12] Discussions with David Olsen during June-August 2010.

from the smaller size of the rights-of-way, which are more vulnerable to invasion by vegetation.[13]

Perhaps most importantly, right sizing transmission creates less uncertainty that transmission capacity will exist to enable the development of renewable resources. Generation and transmission developers are often engaged in a delicate dance, as each looks for the other to commit to a project before they commit themselves. Where transmission capacity exists to high-quality renewable resource areas, however, generation will follow. The U.S. Department of Energy recently confirmed a direct correlation between the extent of renewable energy development and access to transmission capacity.[14] Similarly, where the availability of transmission capacity is uncertain or nonexistent, renewable energy development will stall.[15]

Capturing economies of scale is certainly not a new concept in the energy industry; it has long been used as justification for building large central station generation facilities and the associated transmission lines delivering electricity to loads. However, the energy industry has changed dramatically over the last 15 years, and capturing economies of scale in building transmission lines—as was done historically—has become a dated concept. Since the open access orders,[16] there have been some important changes that have led FERC to address the need for transmission expansion more aggressively.[17] The bottom line remains—FERC policy has guided non-discriminatory access to transmission facilities but has not been able to incent adequate transmission expansion.[18] "Open access transmission without adequate transmission

[13] *See* Transcript of Commission meeting, at 14-15, 22 (May 20, 2010), *available at* http://www.ferc.gov/EventCalendar/Files/20100527073716-transcript.pdf.

[14] 2009 Congestion Study, *supra* note 5, at 18.

[15] *Id.*

[16] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080 (Apr. 24, 1996); Order No. 888-A, 78 FERC ¶ 61,220 (Mar. 4, 1997); Order No. 888-B, 81 FERC ¶ 61,248 (Nov. 25, 1997); Order No. 888-C, 82 FERC ¶ 61,046 (Jan. 20, 1998).

[17] *See generally Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007); FERC Stats. & Regs. ¶ 31,241 (2007) ("Order 890"); *Regional Transmission Organizations*, Order No. 2000, 89 FERC ¶ 61,285 (Dec. 20, 1999) ("Order 2000"). In Order 2000, *et seq*., FERC ordered public utilities to form RTOs or explain why they could not successfully do so. Neither the Northwest nor Southwest successfully established an RTO. Thereafter, in Order 890, *et seq*., FERC required Independent System operators ("ISOs"), RTOs, and other public utilities to establish a transparent planning process that conformed to certain principles identified by FERC. Those principles required utilities to set forth processes for participation in regional planning efforts and address economic planning studies and cost allocation for new projects. FERC also notified non-public utilities that FERC expected them to participate in the planning process required by Order 890 as well. The major planning areas in the West are the California ISO; WestConnect in the Southwest; ColumbiaGrid, which is primarily Bonneville Power Administration ("BPA") and public power entities; and Northern Tier Transmission Group, which is primarily investor-owned utilities in the Northwest and Intermountain West. FERC also convened regional technical conferences to further explore issues, including whether regional or interconnection-wide processes were sufficient to allow integration of large amounts of location-constrained generation and requested comments thereafter. *Notice of Request for Comments*, Docket No. AD09-8-000 (Oct. 8, 2009). On June 17, 2010, FERC issued a NOPR that recognizes the necessity of transmission expansion to access remote resources and addresses some of the barriers to such transmission expansion. 131 FERC ¶ 61,253 (June 17, 2010) (hereinafter "June 17 NOPR").

[18] Indeed, it appears to us that the most robust right sizing of transmission is occurring in the only area of the continental United States not under FERC regulation – the Electric Reliability Council of Texas.

expansion" is today a major barrier impeding transition to a cleaner and more secure energy future.[19] Right sizing—a concept that combines future-oriented planning, economies of scale, and environmental gains--thus offers substantial benefits that will enable the Western states to plan for and achieve higher renewable energy goals and carbon reductions. To meet those goals will require not only an interstate transmission grid; it will also require one that is right sized.

Barriers to Right Sizing Transmission.

Right sizing transmission clearly benefits the natural environment and the development of renewable resources,[20] but the key challenge is how to finance transmission capacity, at least some of which will be uncommitted with no immediate revenue prospects. As this paper will address in some detail below, the current incentives are unlikely to produce appropriately-sized interstate transmission highways, but instead encourage construction of transmission just large enough to meet near-term market and utility native load demand. In fact, it is not yet clear whether any transmission projects aimed at bringing remote resources to the West Coast and Southwest load centers can be built using our existing incentives and regulatory structures. This concern will remain valid even if FERC adopts new rules similar to those proposed in its June 17, 2010 NOPR on interregional cost allocation.[21] For reasons discussed later in this paper, we are concerned about the ability of FERC to implement its protocols in the WECC area in a timeframe that will permit accomplishment of the Western States carbon reduction goals. Thus policymakers must continue to look for alternatives if they wish to see the West meet long-term renewable resource standards and carbon reduction targets.

Procurement patterns for renewable resources present a challenge that complicates financing of major interstate transmission projects and contribute to the difficulty in financing interstate transmission projects to access remote renewable resources. Most utility procurement of renewable resources is in the magnitude of a few hundred MW/year, while major interstate transmission projects are typically 1,000 MW or more. Even assuming that generation developers can absorb the cost of long distance transmission and remain competitive in the power sales markets, most generation developers cannot or will not commit finally to transmission investments until the developer has sold the project or has a power purchase agreement ("PPA") for its output. The one- to two-year procurement cycle for generation output does not mesh well with the much longer transmission development schedule. Generation developers evidence significant interest in interstate transmission projects but often fail to commit or back out when an irrevocable security deposit covering the entire cost of a project's share of the transmission line is required if the developer's renewable project has not been sold

[19] It goes without saying that FERC is bounded by its statutory authority. The scope of that authority has been and will continue to be the subject of debate. In any event, it is not the purpose of this paper to debate what FERC might have done historically. Rather the authors offer reflections on the historic role of the federal government in promoting transmission expansion and what role the federal government might play today.

[20] *See supra* notes 8 through 15 and associated text.

[21] June 17 NOPR, *supra* note 17, PP 170-77.

or does not yet have a PPA.[22] This timing problem makes it difficult to finance transmission projects.[23]

Before the advent of open access transmission policies, it was not unusual for public utilities in the West to build large generation facilities and associated transmission far from load centers at scales that exceeded near-term projected load growth.[24] The utilities would use a portion of those large-scale generation facilities to meet their load requirements, and sell the remaining generation into the growing bilateral Western power market, until needed to meet the utility's retail load growth. This meant that the utility used a larger amount of the generation and related transmission it built from day one—using some temporarily excess capacity to access Western power markets and make wholesale power sales. As the utility's load grew, the generation needed was shifted toward serving the utility's ratepayers and less of the generation and transmission capacity was used for market sales. The transmission lines from Jim Bridger and Colstrip, two coal-fired generating units located in the Intermountain West, are examples of this approach. Both cases worked to the economic advantage of the utilities involved and their ratepayers. Right sizing builds on this approach by considering the environmental dimensions of corridor use.

In the era of open access, however, right sizing transmission lines requires a balancing by planners and policymakers of the optimal size of interstate lines to capture the economies of scale on the one hand, and the timing of future transmission needs on the other. Future transmission needs are driven in part by load growth and in part by the desire to make more clean energy available to displace fossil fuels or the requirement to meet renewable energy standards. How much utilities will invest in renewable energy to displace fossil fuels depends, of course, on state and federal policy and regulation. If facilities are built to economies of scale, some transmission capacity will remain unused—potentially for years—as generation is developed over a period of years to meet load growth and higher renewable energy standards and carbon reduction goals. The uncommitted capacity carries with it significant cost that is accompanied by recovery risk that private lenders will not accept in today's financial markets. Because

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[22] *See, e.g.*, discussion of McNary-John Day upgrades *infra* at pp. 21-22.

[23] At least one group is addressing this timing problem. The Western Governors Association clean energy initiative has resulted in the identification of Western Renewable Energy Zones ("WREZ"). Phase 3 of the initiative's work on WREZ is exploring the potential to coordinate procurement among utilities in the West with the goal of better matching procurement practices to transmission development. New procurement practices that would support right-sized transmission projects should be pursued, but should not deter or delay consideration of near-term federal support for high-priority transmission projects.

[24] Lest it appear that we have forgotten our history, let us note that the authors are well aware of the cost of faulty planning assumptions such as those that led the Northwest into planning to plan, and in some cases to partially or completely construct a large number of nuclear plants in the 1960s and 1970s and the resulting financial debacle. We note, however, that the completed remote central station plants and transmission investments from that era generally proved extremely cost-effective (in an era when carbon reduction was not our focus). With improved planning tools and significant experience about what has and has not worked, however, the region is better situated to identify the appropriate size of the interstate transmission highway needed for the next decade or two. Moreover, even if load growth projections prove substantially wrong, great value will be derived from new transmission facilities that allow more of our power to be derived from no-carbon or low-carbon sources.

neither utilities nor financiers like risk of cost under-recovery,[25] transmission developers naturally build to accommodate committed capacity only, sacrificing the economies of scale to the practicalities of financing a new transmission line.[26]

As a result, transmission developers have attempted to alter the concept of right sizing in order to minimize the risk of stranded investments. For example, the initial phase of a right-sized 2 x 500 kV project could include building the towers for the ultimate project, but would string the conductor initially on only one side. This would limit the potential stranded investment risk to that associated with the slightly heavier towers necessary to carry two circuits instead of one. Substations (breakers/transformers) could be designed for the ultimate build-out or only for the initial phase. In the latter case, building substations large enough to accommodate additional transformers is a small added cost; the major cost of the transformers and breakers themselves would be incurred only when the second phase was built. Configuration options provide opportunities to manage initial costs/risks and can change the initial financial guarantees needed significantly. They also provide opportunities to manage second or final phase build-out to minimize or eliminate construction outages. However, configuring transmission projects this way may result in regulatory inefficiencies and prolonged uncertainty. Transmission developers may be told to return for additional regulatory approvals when they are ready to proceed with subsequent phases of a project, thus sacrificing regulatory efficiency and causing generation developers to doubt whether the ultimate transmission project will ever go into service. Regulators could help to eliminate such uncertainties by approving the ultimate project while allowing for delayed implementation, *e.g.*, all project phases are approved so long as they are put in service within a 10-year time frame.

Merchant transmission developers, for example, must bear the full financial risk of their transmission investments until such costs can be passed on to transmission customers. However, developers are also expected to pay their lenders as soon as a transmission project enters service. Thus, merchant transmission developers must be able to substantially pre-subscribe a project's capacity using open seasons in order to meet the needs of its lenders. If the developer cannot pre-subscribe its project, then it risks losing financing if it continues with plans to build capacity that will not produce immediate revenue. It is therefore no surprise then that merchant developers scale their projects downward to reflect, and not exceed, market interest (*i.e.*, pre-

[25] Unused transmission capacity or oversized infrastructure (towers, substations, etc.) create the risk of stranded investment, *i.e.*, the future revenues gained from a transmission project are less than the project's fixed and operating costs. Stranded investments may occur when transmission facilities go underutilized because of changing generation technologies or the relative cost-effectiveness of other resource areas or transmission options. In addition, stranded investments are borne by ratepayers and/or shareholders, and thus transmission developers and regulators alike aim to keep stranded investments at a minimum.

[26] This is generally true whether it is an integrated utility developing a new transmission project or a merchant transmission developer. If the transmission project sponsor is an integrated utility, its state regulators often will not or cannot allow recovery for "excess capacity" from which the utility's ratepayers may not benefit immediately, or perhaps ever with respect to exported power. If a merchant transmission developer is the project sponsor, then the developer must begin debt repayment when the transmission project goes into service. If initial customers rates for service are based only on their *pro rata* share of the transmission project's costs, then the developer's revenues from customers will not cover its debt service until all the capacity of the line is committed. Either way, the most common responses of a project sponsor is to down-size the line, put the transmission project on hold until it can market more capacity, or abandon the project.

subscribed transmission service). As markets emerge, the transmission developers will want to incrementally increase transmission capacity to, once again, reflect the near-term market. Such an approach to developing transmission capacity fails to capture the efficiencies afforded by right sizing.

The relative economics of local renewable resources versus remote renewable resources acts as a barrier to building a robust interstate transmission system. At current renewable energy targets, many utilities can meet their obligations by using in-state resources.[27] Further, certain states have enacted policies that allow relatively few imported renewable resources to count toward renewable energy targets,[28] limiting the current need for transmission to allow remote renewable resources to participate in such markets. As renewable energy and carbon reduction targets climb higher, however—recent history shows that such increases are likely—utilities will be without additional cost-effective, local resources and will be compelled to source additional renewable energy from remote locations. In other words, relative economics will eventually favor remote resources. If the West diverts its attention from interstate transmission now, then there will be no renewable energy market in the West when it is needed. And, as discussed throughout this White Paper, such interstate transmission must be right sized to enable the development of renewable resources to serve that market.

The divergent planning horizons associated with transmission and generation also acts as a barrier to constructing the right-sized interstate transmission grid needed to enable the West to meet long-term carbon reduction goals. State utility commissions often focus more on short-term costs to ratepayers than long-term benefits, and utilities are reluctant to plan portfolios of clean energy services that do not fit their current business models. Thus, utilities are apt to consider transmission needs on horizons that are too short to take into account long-term public policy goals. During the open-access era, typical planning horizons have been five or 10 years. More recently, some of the transmission planning horizons look forward 20 years.[29] As a result, current transmission planning horizons—which fail to account for long-term energy security, economic development, and environmental goals (increasing levels of state Renewable Portfolio Standards, GHG reduction targets, water use reduction targets, habitat protection targets, etc.)—restrict transmission planners from realizing the benefits and efficiencies that could be gained through right sizing.

Current Interstate Transmission Proposals.

At present there are an unprecedented number of interstate transmission projects already proposed throughout the Western U.S., as shown in Figure 4. Many of these proposals aim to provide access to the remote wind resources in Montana and Wyoming, including Chinook, the Montana-Alberta Tie Line ("MATL"), the Mountain State Transmission Intertie, Wind Spirit, Zephyr, and others.

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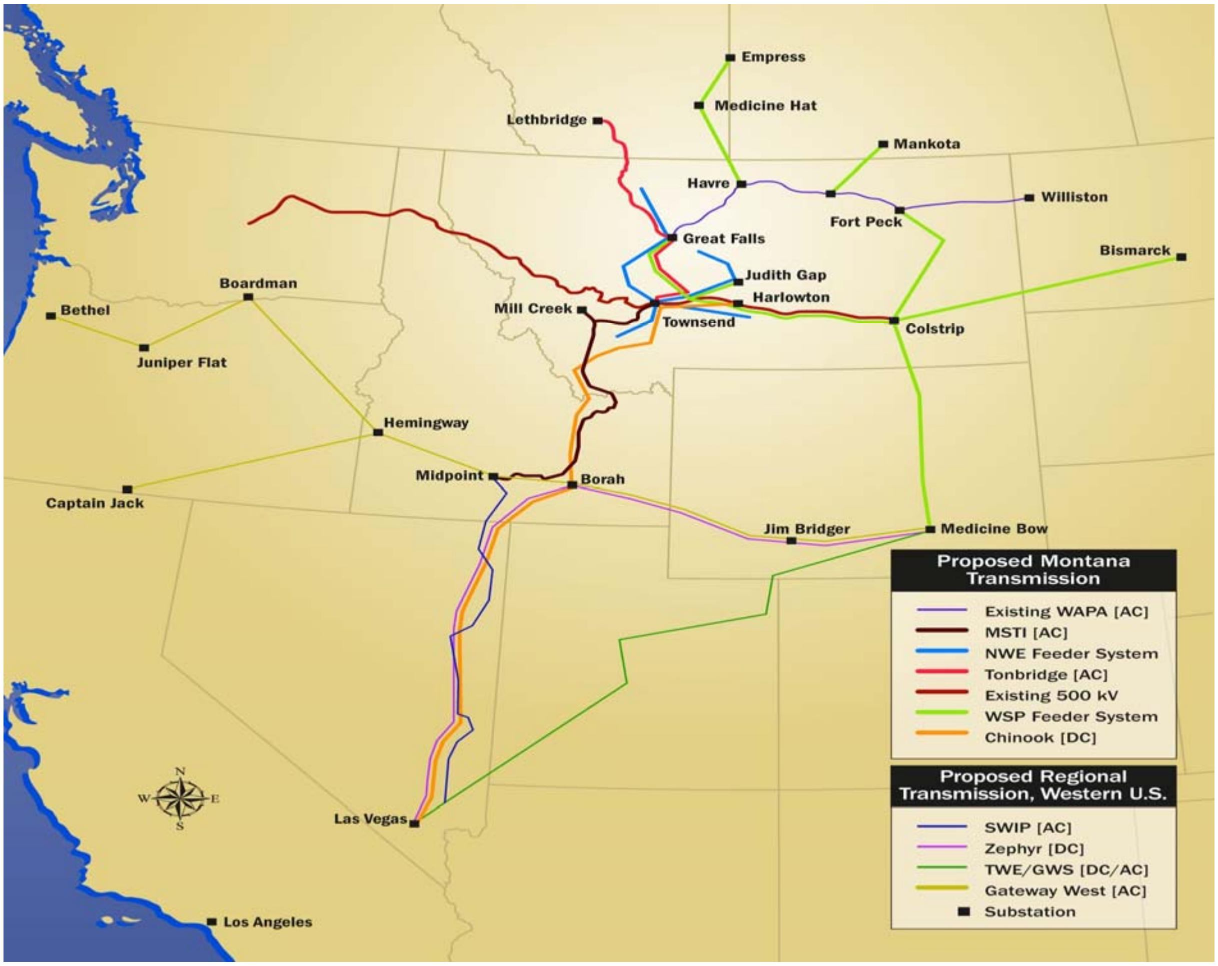
[27] John Farrell & David Morris, *Energy Self-Reliant States: Second and Expanded Edition*, at 28, The New Rules Project (May 2010), *available at* http://www.newrules.org/sites/newrules.org/files/ESRS.pdf.

[28] California, for example, may allow its utilities to use out-of-state renewable resources to meet only up to 40% of their renewable energy obligations.

[29] The SPP's Integrated Transmission Plan, for example, received much acclaim from FERC. The proposal looks forward as far as 20 years. *Southwest Power Pool, Inc.*, 132 FERC ¶ 61,042, P 8 (July 15, 2010).

Figure 4. Proposed Transmission Projects[30]



Some of these projects are making progress, others seem to have stalled, but only a few have a clear path to completion. However, financing and cost recovery remain barriers for most of them, with the notable exception of MATL, whose funding is discussed below.

But before turning to the question of what could be done to facilitate transmission expansion and access for high quality, remote renewable resources in the West, we will briefly review the history of Western transmission development.[31]

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[30] Mont. Governor's Office of Econ. Dev. & Mont. Dept. of Commerce, Energy Promotion and Dev. Div., *Montana Transmission for America*, at 1 (Dec. 2009).

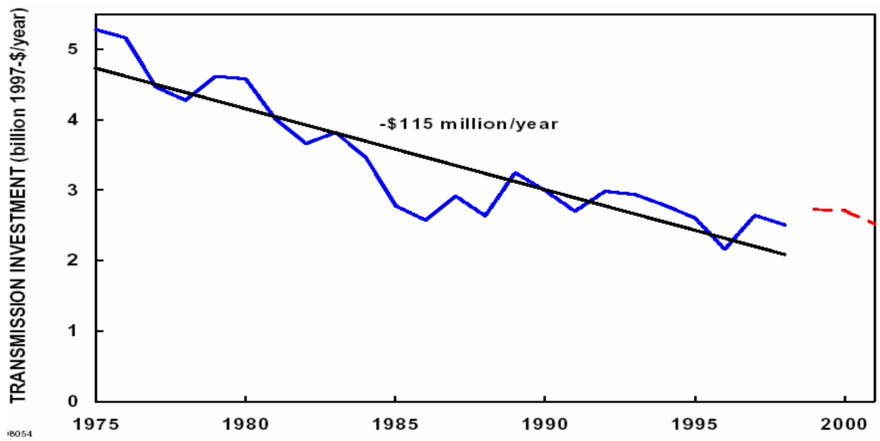
[31] This paper was substantially completed prior to the June 17 NOPR, which proposes new planning and cost allocation requirements. The NOPR requirements, if successfully implemented, could lead to increased transmission access for remote resources that is the concern of this paper. But, FERC's incremental approach to addressing the key barrier of cost allocation will at best result in significant delay and at worst will fail to incent the right-sized interstate transmission highway necessary to access high quality, remote renewable resources in the West.

TRANSMISSION DEVELOPMENT IN THE WEST

Declining Investment.

Most Western transmission was constructed prior to FERC's issuance of Order 888 in April 1996, providing for third-party open access to transmission systems.[32] In fact, most major new lines within WECC were constructed by 1975. Although the open access orders accomplished wonders in allowing the broader use of existing facilities, relatively little major transmission has been constructed in the 14 years following that order. At the time of open access, FERC did not have the regulatory tools available to facilitate transmission expansion, and consequently transmission expansion has languished since.[33]

Figure 5. Transmission Investments[34]



Annual transmission investments from 1975 through 1998 and projections for 1999 through 2001.

In fact, as of 2003, transmission investments, adjusted for inflation, had declined for almost 25 years at an average rate of $115 million per year.[35] The inflation-adjusted investment in transmission during 1999 was less than half of what it had been 20 years earlier.[36] Moving remote resources to population centers requires long interstate lines. Figure 6 shows the interstate transmission built in the West from 2000 to 2007—a total of 170.5 miles.

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[32] 75 FERC ¶ 61,080; *see also* Order No. 888-A, 78 FERC ¶ 61,220; Order No. 888-B, 81 FERC ¶ 61,248; Order No. 888-C, 82 FERC ¶ 61,046.

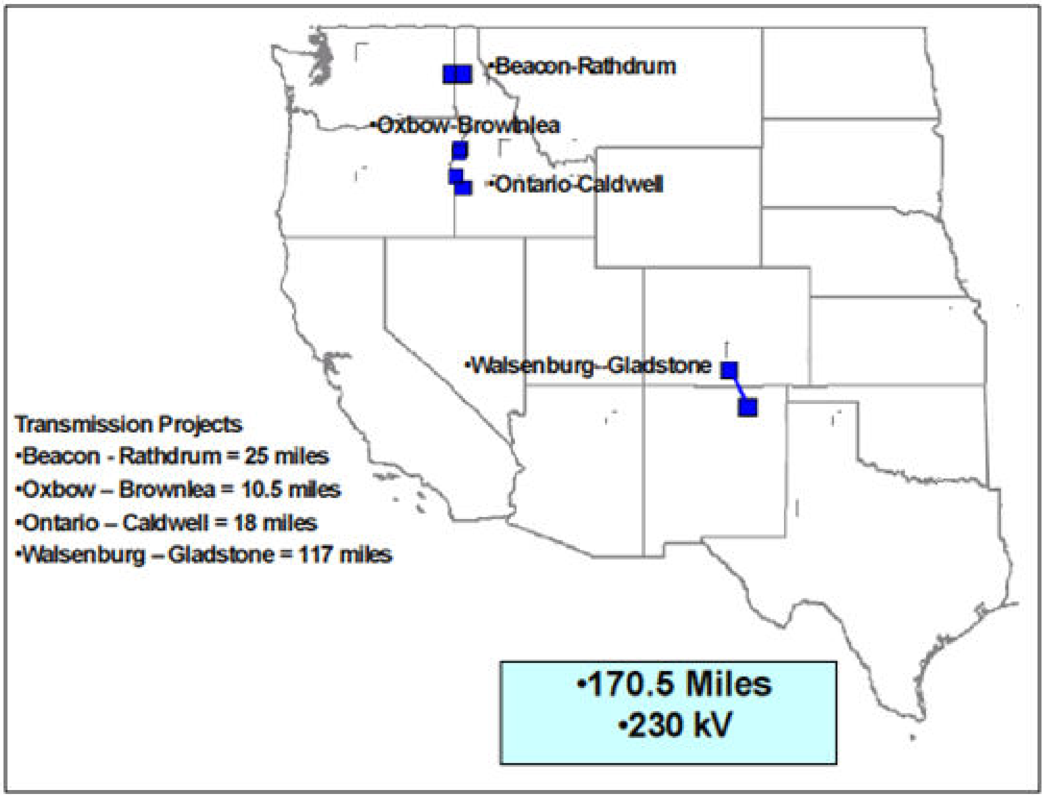
[33] The authors note that transmission is developed in lumps. The West had much available transmission capacity until the late 1990s and there was little need for additional transmission to be built. In addition, years of low gas prices increased the development of cost-effective natural gas resources near load centers that required little or no transmission. It was only after the Western transmission surplus disappeared and the energy market crisis that new interest in transmission developed.

[34] U.S. Department of Energy Transmission Bottleneck Project Report, Consortium for Electric Reliability Technology Solutions (CERTS), at 13 (Mar. 19, 2003), *available at* http://certs.lbl.gov/pdf/iso-bottle-03.pdf (projection in red).

[35] *Id.*

[36] *Id.*

Figure 6.[37] INTERSTATE TRANSMISSION PROJECTS COMPLETED 2000-2007



How Transmission Was Constructed Prior to Open Access.

Prior to the institution of transmission open access, transmission was built by individual utilities primarily for their own or shared needs. These needs were (1) delivery of power from the utility's owned generation to its retail loads, (2) facilitating the utility's purchases of energy for its retail loads and sale of surplus energy from its generation facilities, and (3) assuring the reliability of the utility's electric system. Generally, utilities did not build transmission outside of their retail service footprint, so that cooperation with neighboring utilities was necessary to build long-distance lines. In addition, because some lines benefited multiple utilities, long-distance lines were often jointly owned. Provision of transmission services to third parties usually was not even a consideration—the line owners planned and built transmission to meet their own needs. These principles can be illustrated by looking at some of the largest transmission facilities in the WECC area that were built during the 1960s and 1970s, which include the following:

(i) Northwest to California Interties: The three major AC transmission interties and the DC transmission intertie between the Northwest and California were built by the BPA, with

[37] NERC Summer and Winter Assessments; WECC Existing Generating and Significant Additions and Changes to System Facilities Reports; FERC's Transmission Database; FERC, Office of Energy Projects, Electric Transmission Siting (2007), *available at* http://www.ferc.gov/industries/electric/indus-act/siting/trans-siting-present.pdf.

federal funds, for the marketing of surplus power from federal hydroelectric facilities.[38] The interties used parts of the existing transmission systems of Portland General Electric Company and Pacific Power & Light Company, and as a result, these companies obtained firm transfer rights in the intertie. Because even BPA operated only within its service footprint, ownership of the intertie shifted to California utilities at the Oregon-California and Oregon-Nevada border (for the DC intertie). The California utilities jointly constructed their portion of the intertie facilities, to allow them access to relatively inexpensive power from BPA, as well as to make seasonal capacity exchanges with BPA. The California utilities also entered exchanges and power sales agreements with the investor-owned Northwest utilities with interests in the interties.

(ii) WAPA: Substantial transmission facilities were constructed in the Intermountain West by the Western Area Power Administration ("WAPA"). These facilities were built to move power from federal hydroelectric projects to the utilities using the output of such facilities to meet their retail loads.

(iii) BPA: Likewise, major transmission facilities were constructed by the BPA to move power from the Columbia River federal hydroelectric generating facilities to utilities and direct service industrial customers using the output of such facilities to meet their retail loads. These included cross-Cascades lines and major north-south lines within the Northwest in addition to the interties.

(iv) Montana Intertie: The major 500 kV transmission lines between Montana and the Pacific Northwest were built by owners of the Colstrip coal units to permit the delivery of output from that facility to the Pacific Northwest loads of these owner-utilities. The assistance of BPA was sought when siting problems on tribal land arose and the line was reconfigured and part of the route moved into an area that was within the system footprint of BPA. BPA then built and assumed ownership of the remainder of the lines, subject to prior agreements from the Colstrip owners that assured BPA of full payment for its cost of building and operating its portion of the line.

(v) Cross-Cascades: The major interconnection from Idaho over the mountains to the West is the Midpoint-Malin line. This line was built by PacifiCorp to move power from its coal plants (primarily the Jim Bridger units in Wyoming) to serve PacifiCorp's loads in the Northwest. The portion of the Bridger transmission that fell in Idaho Power Company's footprint, however, had to remain under the ownership of Idaho Power (a part owner of the Jim Bridger coal plant).

(vi) Southwest to California: Major lines from Southern California into Nevada and Arizona were built by California utilities to move power from coal and nuclear facilities owned by these utilities. These plants included the Palo Verde nuclear unit, rights in the Navajo coal-fired units, and rights in the Intermountain coal units.

[38] Two of the three AC lines that compose the California-Oregon Intertie were put in service in 1968 and 1969. The third AC line from The Dalles Dam in Oregon to Tesla, east of San Francisco, was completed in 1993. Northwest Power Planning Council, *Pacific Intertie: The California Connection on the Electron Superhighway*, at 8 (May 2001), *available at* http://www.nwcouncil.org/LIBRARY/2001/2001-11.pdf.

Even though these utility transmission facilities were built for the use of the constructing entities, more and more utility systems became interconnected as lines were added to the Western grid. These interconnections enabled power to be transmitted across multiple utility systems, and created the need for voluntary associations and agreements to coordinate the transmission planning and operations over the interconnected systems. The transmission facilities were not built with any explicit goal of creating a West-wide grid.

Because the Western interstate transmission system is the product of construction efforts by individual utilities to meet their own or shared needs, the pattern of flows on the WECC grid has evolved to be unbalanced. Most of the major transmission runs up and down the West coast areas to facilitate seasonal exchanges and from California into Arizona and Western Nevada. The East side of the Western grid has fewer and smaller population centers and thus did not need particularly large transmission facilities to connect serving utility generation to loads. Thus arose what is commonly referred to in the West as "the weak east side of the donut," or weak interconnections on the East side of what might be thought of as a large transmission circle around the WECC area. This East-side weakness impairs both the use and potentially the reliability across the Western grid. The East side is also where the most attractive large-scale renewable energy resources are located.[39]

COST RECOVERY

Transmission gets built only if its developers have a strong assurance that they will be compensated. Cost recovery for transmission developers was relatively easy to determine where developers were building transmission for their own use and for the benefit of their retail customers. The pre-open access allocation approaches, however, did not address how to allocate cost or assure payment for transmission needed to create a robust system for third-party use, or how to create a strong interstate transmission grid. Incentives from the previous regulatory scheme are likely not effective to promote development of a transmission system suited to delivering renewable resources developed in large part by independent power producers rather than integrated utilities—particularly if those resources are remote from the population centers where the power was most needed. Now the limited amount of capacity over the pre-existing transmission system is heavily restricted on a firm basis. As energy experts and policy makers are well aware, major new construction of renewable or other resources requires *both* new transmission and new means of financing and cost recovery. A broader look at the issue of financing and cost recovery is essential if we are to build the transmission interstate highways needed for a robust interstate market in renewable energy. FERC squarely recognized this problem in its June 17 NOPR and companion decision on cost allocation in SPP:

> Cost allocation reform is one of the most difficult issues facing transmission service providers and regional transmission organizations (RTO)/independent system operators (ISO) . . . . This is especially true given the changing circumstances affecting the transmission grid including, particularly the need to upgrade

[39] As a result, building significant transmission on WECC's Northeast side would enhance reliability of the entire interconnection as well as permit export of renewable energy.

> existing transmission infrastructure and build new transmission facilities to satisfy the expanding demands on the transmission system. Efforts to integrate new resources, including significant amounts of location-constrained generation, into existing transmission systems and to address renewable portfolio standards and other regulatory policies challenge existing cost allocation and transmission planning protocols.[40]

Pre-Open Access Financing and Cost Recovery.

In the pre-open access world, as noted above, transmission generally was not built for the benefit of parties other than the transmission owners themselves. Thus, cost recovery was relatively easy. Transmission was sized for the needs of the constructing utilities and the costs were passed on to the customers of such utilities. In the case of BPA and WAPA, these agencies passed the cost through in rates the agencies had the authority to establish themselves, with minimal FERC regulatory overview. In the case of investor-owned utilities, the pass-through had to be approved by state retail regulators for allocation to retail customers based on a "need" for the facilities. Naturally, "need" did not consider third parties, as wheeling service was not a substantial consideration in transmission line construction. However, in certain limited cases transmission projects were built to economies of scale, but that typically happened where a utility could justify the initial excess capacity as a benefit to its retail ratepayers.[41]

Financing and Cost Recovery Efforts in the Open Access Era Have Had Mixed Results.

We can gather strong lessons from prior financing and cost recovery efforts, successful and not successful, as engaged in since 1996 when the open access era began. The bottom line, however, is that these efforts have not resulted in adequate advances toward the type of robust transmission system needed for the West, particularly if we are to access our most attractive renewable resources.

[40] *Southwest Power Pool*, 131 FERC ¶ 61,252, P2. For the first time, in the June 17 NOPR, which was issued contemporaneously, FERC proposed new requirements to integrate regional and inter-regional planning and cost allocation. As noted elsewhere, the authors are concerned that the FERC proposal will encounter substantial delays and may prove impossible to implement over state utility commission objections in areas without RTOs. Other solutions should be pursued simultaneously if the renewable energy standards and carbon reduction targets already in place in the West are to be timely met.

[41] Arguments could be made based on the cost savings to utilities ratepayers for building one larger project some years before all the capacity was needed. But building projects with a significant amount of excess capacity worked best when the utility also had excess generation that it could use for off-system sales if it could get the power to the Northwest coast population centers. Thus the PacifiCorp project to bring power from its Jim Bridger coal plant in Wyoming, across Idaho and the Cascade mountains to tie into north-south lines it owned, allowed the utility both to serve its growing load on the West side of the Northwest and to sell excess power to California or other Northwest utilities. The additional transmission capacity, not immediately needed for load, nonetheless benefitted PacifiCorp's ratepayers through the crediting of revenues for off-system sales.

FERC Tariff Solutions.

As part of open access, FERC promulgated tariff rules that require transmission providers to construct network upgrades needed by new generation customers, subject to up-front payment by the customers for such facilities.[42] FERC's default policy is that generation customers receive transmission credits that can be applied against their transmission rates, in return for up-front payments.[43] In the Eastern Interconnection, FERC has approved cost allocation methodologies that may allow for little or no refund to the generation customers who may be fully responsible for funding transmission lines.[44]

FERC's approach works relatively well in situations in which only modest transmission upgrades are needed to accommodate a particular generation customer. The generation customer simply makes the necessary payment as a slight addition to its project capital costs. The system breaks down, however, in situations that require major new transmission lines, as illustrated by the McNary-John Day example below. The costs simply become too great relative to individual generation project economics.[45] The system also can break down in situations where a line will

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[42] *Standardization of Generator Interconnection Agreements and Procedures*, 104 FERC ¶ 61,103, PP 675-750 (2003); FERC Pro Forma Large Generator Interconnection Procedures §§ 12.2.2, 12.2.3

[43] *Id.*

[44] For example, the current version of Attachment FF to Midwest Independent Transmission System Operator's ("MISO") Tariff states that (a) 100% of construction costs will be allocated to generators for new transmission lines operating below 345 kV and (b) 90% of construction costs will be allocated to generators for lines operating at or above 345 kV (with the remaining 10% being allocated on a system-wide basis). The MISO filed this cost allocation methodology in Attachment FF to its Tariff on July 9, 2009 in Docket No. ER09-1431-000. FERC conditionally approved the filing at 129 FERC ¶ 61,060 (Oct. 23, 2009). A new MISO proposal was filed July 15, 2010; that proposal would spread costs to all MISO loads of certain projects deemed "multi-value" projects, but other network upgrades for generator interconnections would continue to be subject to the 90%-10% rule. Docket No. ER10-1791-000. SPP recently received FERC approval for a cost allocation methodology dubbed "Highway/Byway," which allocates costs as follows: (i) the costs of transmission facilities operating at 300 kV and above are allocated 100% across the SPP region on a postage stamp basis; (ii) the costs of facilities between 100 kV and 300 kV are allocated one-third across SPP on a postage stamp basis, and two-thirds to the zone where the facilities are located; (iii) facilities 100 kV and below are allocated 100 percent to the zone where the facilities are located. Where facilities are associated with transmission service from a wind resource and are located in the same zone as the transmission customer's point of delivery, Highway/Byway will apply. Where transmission facilities are located in a different zone than the point of delivery, Highway/Byway will only apply to facilities operating at 300 kV and above. Facilities operating at less than 300 kV will have two-thirds of the costs allocated across the SPP region, with the remaining one-third allocated to the transmission customer. Highway/Byway, however, does not apply to generator interconnection upgrades. *Southwest Power Pool*, 131 FERC ¶ 61,252, PP 10-12, 123. In SPP, generator interconnection upgrades are allocated 100 percent to the interconnection customer(s), and the interconnection customer has the possibility (but not guarantee) of a refund. SPP Tariff, Attachment V, § 4.2.5(b); Attachment Z2. SPP has not yet developed a mechanism to provide interconnection customers with such refunds. In PJM Interconnection, interconnection customers are allocated 100% of generator interconnection costs that would not otherwise be incurred under the Regional Transmission Expansion Plan but for the interconnection request. PJM Tariff, Part VI, subpart B, § 217.

[45] The transmission cost of a renewable energy project may simply be too high to permit a profitable sale of the project or its output. There is another problem, however, when a transmission developer requires generation developers to agree to pay a pro-rata share of all the transmission project's costs without capping a developer's exposure. Under such an arrangement, 10 100-MW projects may each be willing to pay a pro-rata share of a $100 million transmission project, but the fine print may require projects to pick up a larger share if one or more of the 10 developers pulls out, which in the most extreme situation may leave one project responsible for the full $100 million

(continued . . .)

serve multiple purposes—that is, serve generation customers, provide reliability, and accommodate other energy economy transactions. In this situation, the central questions are how to assign benefits for a multi-purpose line and, perhaps more difficult, how to assign values to those benefits.[46]

McNary-John Day (2002).

BPA's initial pre-subscription process for the McNary-John Day line provides an excellent case study in what does and does not work in an open access market. The McNary-John Day line is a 79-mile, 500 kV single circuit transmission line with terminal points at Umatilla, Oregon and BPA's John Day substation in Sherman County, Oregon. The line, originally budgeted in 2002 as a $117 million project,[47] was intended to relieve major transmission constraints that exist along some of the richest wind resources areas in the Pacific Northwest. There were also substantial non-renewable resources in the area. After BPA signaled that it intended to build the line, BPA and its customers saw the cost allocation drama play out.

BPA made construction of the line contingent upon advance agreements of generation developers to pay the cost of the line, pro-rated over the relative amount of capacity taken by each developer. In order to assure that BPA was made whole for its construction costs, a failure by any such developer to meet its payment commitments would result in those commitments being pro-rated over the remaining developers who signed advance agreements for such funding. This approach was in line with FERC's pro forma tariff requirements.

Although the proposal seemed workable on the surface, it was doomed from the start. The transmission queue for transmission service requiring the McNary-John Day line substantially exceeded the capacity of the line and thus the cost of the line, as allocated among the transmission customers, seemed relatively small. However, before the generators could be confident of their ability to make use of the line, they needed to complete their facility siting processes and negotiate PPAs. Unfortunately, at the time there was less demand for generation in that area than there were customers in the transmission queue.

When the generation developers inevitably could not assure in advance a market for their output, they withdrew one by one, as their queue position was reached, from the open season. The rules under this initial open season required assumption of risks that very few developers and their funders would agree to take. Not surprisingly, McNary-John Day did not go into

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(. . . continued)
cost. Thus, when it comes time to make the commitment to pay whatever one's eventual share of the costs is, developers fall like dominos. See the discussion of McNary-John Day case study *infra* at pp. 21-22.

[46] These are the issues FERC acknowledges in the June 17 NOPR and proposes to require each planning region to develop separate planning and cost allocation proposals with each of its neighboring planning regions that will address, at a minimum, transmission projects aimed at satisfying state and federal regulatory requirements relating to renewable energy standards and carbon reduction, and requiring a form of cost allocation that does not assign 100% of costs to generation developers. This is a necessary, but likely insufficient, step in the right direction.

[47] Bonneville Power Administration, *McNary-John Day Transmission Line Project Record of Decision*, at 1 (Oct. 30, 2002), *available at* http://www.bpa.gov/corporate/pubs/rods/2002/tbl/ROD103002.pdf.

construction. This lesson is being relearned in other contexts, most recently in response to cost allocation proposals made within the MISO process.[48]

Open Seasons.

An open season process allows a transmission developer to gauge market interest by offering capacity on a proposed transmission project through public auction. Open seasons were traditionally used by merchant transmission developers because they have no rate base[49] from which to recapture the costs of investments. Generation developers who acquire capacity through auction will not pay the up-front costs of developing the line. Instead, they simply commit to pay for transmission service for a specified period of time. A transmission developer's hope is that generation developers will reserve the full capacity of the proposed transmission project at the auction, giving the transmission developer adequate assurance that a market exists for its project. Of course, there is the possibility that generation developers will not deliver the desired market signal, thus causing a transmission developer to delay its project until a market emerges, resize the project to reflect market interest, or cut its losses and walk away. What is nearly guaranteed, however, is that a transmission developer will not build transmission capacity for which there is no immediate customer.

Transmission open seasons have been used with only modest success. More recent open seasons have improved on failed attempts from the past but have still not managed to result in major transmission development. Fundamental problems inherent in the open season process have caused it to be inadequate for assuring on a reliable basis the construction of needed large transmission projects. In particular, open seasons do not address the disconnect between the necessary planning horizon for the transmission development and the substantially shorter planning time for utilities to commit to purchase generation output.

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[48] MISO narrowly escaped a similar "domino effect" to the one experienced with its pre-subscription process for McNary-John Day, in connection with the Brookings Line, a proposed 345 kV line from South Dakota to near the Twin Cities in Minnesota that would provide significant new access for wind generation. MISO determined that a cluster of 12 wind projects with 1200 MW under development should pay the full cost of the line, designed as part of a transmission reinforcement and overlap project of a group of utilities in the region. The MISO tariff contains provisions allowing MISO to require generation developers to prefund certain construction needed for their interconnection. In the case of the Brookings Line, each wind developer was being asked to put up security equal to its pro rata share of the full $700+ million cost of building the line, with advance funding of construction to begin almost immediately for a line scheduled for completion years from now or, in the alternative, draw downs on the developer's letter of credit as the transmission owners needed the funds for construction. Several projects withdrew from the queue and others were struggling to find a way of avoiding withdrawal, when FERC ruled that MISO had not adequately supported its decision to include the full cost of the Brookings Line in the generator interconnection agreements of the group of wind developers and ordered, among other things, a restudy to determine the extent of facilities for which the wind projects were the "but for" cause. *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 FERC ¶ 61,165 (May 20, 2010) (a/k/a "Community Wind II Order"). As a result of this order, MISO put the wind developers' interconnection agreements on hold.

[49] In regulatory utility rate-making parlance, "rate base" is an investment that a rate-setting authority recognizes as appropriately recoverable in utility rates. For such an investment, the utility is allowed to recover both a "return of" investment (in the form of depreciation or amortization) and annual percentage "return on" the undepreciated or unamortized portion of such investment.

Wyoming-Colorado Intertie.

The Wyoming-Colorado Intertie illustrates the shortcomings of the open season process. The Wyoming-Colorado Intertie is a 180-mile, 345 kV transmission line proposed to connect the Laramie River substation at Wheatland, Wyoming to the Pawnee substation at Brush, Colorado.[50] The value of this transmission line seems apparent. In the first place, the line would relieve a major interstate transmission congestion problem, identified in Figure 2 as "TOT-3." Moreover, the line would bring 850 MW of transmission capacity to a rich wind resource area.[51] Unfortunately, there is no mechanism in place for the developer to allocate in advance any of the cost of the line to retail utilities that will benefit from relief of this congestion.

Because of the robust wind area in Wyoming, the developers of the Wyoming-Colorado Intertie attempted to pre-subscribe the project's capacity through an open season. The process was initially declared a success, as two agreements were obtained by the developers through this process for the sale of 585 MW of the line's capacity.[52]

Unfortunately, the open season approach could not overcome the basic transmission financing and cost recovery dilemma. On the one hand, transmission developers need advance assurance that the moneys invested in a new line will be recoverable from users of the new line. On the other hand, new users usually will not make a final commitment until they know that all other agreements needed for their use are in place. The Wyoming-Colorado Intertie developers sought to alleviate this problem by including a walk-away right in the subscription agreement that gave generation developers the right to terminate their contracts if, within a short period, they were unable to sell their output to utilities in Colorado. Pursuant to this provision, both subscribers have withdrawn from their contracts and the transmission line currently has no capacity subscribers.[53] As a result, this attractive and beneficial project is currently on hold.

Chinook/Zephyr: The Anchor Tenant Solution.

FERC approved a developer's proposal to overcome the open season problems with an "anchor tenant" solution. The Chinook and Zephyr projects consist of twin 1,000-plus mile, 500 kV direct-current transmission lines that will connect the wind-rich areas of Montana and Wyoming with markets in the Southwest.[54] Each of the two lines could carry approximately 3,000 MW of renewable resources.

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[50] *See* Wyoming-Colorado Intertie Transmission Project, Overview, http://www.wcintertie.com (last visited Aug. 10, 2010); *see also* Wyoming Infrastructure Authority, Wyoming-Colorado Intertie Project, http://wyia.org/projects/transmission-projects/wyoming-colorado-intertie-project-wci/(last visited Aug. 10, 2010).

[51] *See* http://wyia.org/projects/transmission-projects/wyoming-colorado-intertie-project-wci/.

[52] *See* Wyoming Infrastructure Authority et al., Open Season a Success for Wyoming-Colorado Intertie (Aug. 26, 2008), www.wyia.org/Docs/Announcements/PressReleaseOpenSeasonOutcome 8 26 08.pdf.

[53] Matt Joyce, "Developers: Timing key to Wyo-Colo power line," Wyoming Tribune (Mar. 15, 2010), *available at* http://trib.com/news/state-and-regional/article_c45524a5-72ac-5434-bea3-139a09870df2.html.

[54] *See* TransCanada, Zephyr and Chinook Power Transmission Lines, www.transcanada.com/zephyr.html (last visited Aug. 10, 2010).

The developer, TransCanada, recognized that the open season process—which already proved inadequate for the much smaller 850 MW Wyoming-Colorado Intertie—almost certainly would not result in the necessary capacity pre-subscriptions needed to support approximately 6,000 MW of total project capacity. TransCanada then held numerous conversations with creditworthy parties, seeking an anchor tenant. As proposed by TransCanada, the anchor customer on each project would be required to purchase 1,500 MW of transmission service at negotiated rates for a minimum term of 25 years.[55] The anchor customer would not be required to accept any of the additional capacity, even if unsubscribed after an open season process, for the remaining one-half of the capacity.[56] Only one customer initially qualified for the Chinook negotiations, and no binding anchor tenant arrangement was reached.[57]

The anchor tenant approach has suffered from the same problems that have made the open season process relatively ineffective—risk aversion by transmission developers and their financiers. Transmission developers alone cannot support the financial weight of these projects on their own pre-existing balance sheets, and thus they have looked to generation developers to commit substantial funds and make binding commitments years before either a generation project or the transmission capacity will become operational. Depending on the projected cost of a transmission line and the number of generation customers across which such costs may be spread, the up-front funds that generation developers must commit can be well beyond the abilities of small or medium-sized developers, and can constitute a "bet-the-company" investment for even very large companies. In light of the many uncertainties surrounding transmission projects, it is not surprising that generation developers have thus far remained on the sidelines. If a properly-sized interstate transmission highway is to be built—as opposed to a patchwork of transmission facilities that provide an insufficient and inefficient path from remote resources to markets—there must be a mechanism to bridge the initial revenue gap. That bridge, as BPA has figured out, must come in the form of federal financing.

McNary-John Day Revisited.

BPA later took heed of the lessons learned in its initial unsuccessful subscription efforts for the McNary-John Day line. Additionally, BPA incorporated the concept of an open season with a variation from other open season efforts that proved successful: rather than charge generation developers the full cost of the line up front, BPA found other reasons, such as reliability, to use federal bridge money to finance the line and recoup its costs over time through transmission service rates. In February 2009, BPA announced that it had decided to build the line without a required pre-subscription.[58] BPA stated in its announcement that it was able to make this decision as a result of obtaining federal capital support.[59] The ARRA provided BPA

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[55] *Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134, P 12 n.9 (Feb. 19, 2009).

[56] *Id.* P 12.

[57] *Id.*

[58] Letter from Bonneville Power Administration to Customers, Constituents, Tribes and other Stakeholders, at 1 (Feb. 19, 2009), *available at* http://www.transmission.bpa.gov/PlanProj/Transmission_Projects/mcnary/letter_-_McNary-John_Day_NOS_announcement_letter.pdf.

[59] *Id.*

with an additional $3.25 billion in federal borrowing authority,[60] and thus enhanced BPA's ability to build the line without pre-subscriptions.

Although the decision to proceed with the McNary-John Day project was finally made in February 2009, the project had been part of BPA's 2008 Network Open Season. This new attempt at an open season differed substantially from BPA's earlier failed pre-subscription attempt. This time BPA recognized that transmission projects serve reliability and other public purposes, such as accessing new renewable energy resources, and that up-front financing of projects using federal funds can make a critical difference. BPA agreed to construct transmission upgrades, under certain conditions, where generation developers and utilities agreed to make commitments to future transmission service.[61] The commercial arrangements for the new open season did not require up-front funding by developers, although developers were required to post security for the equivalent of one year's transmission service cost at BPA's postage stamp transmission service rate.[62] This requirement, while a barrier for some developers, was manageable by others—enough so that BPA is developing three other important transmission reinforcement projects as a result of the 2008 Network Open Season and has sold more than 3,000 MW of transmission capacity resulting from transmission reinforcements built with federal support, the vast majority of which is for transmission service to new wind projects in the Columbia Gorge area of Washington and Oregon.[63]

BPA plans to have the McNary-John Day line in service by late 2012.[64] Although the construction cost is supported by federal funds, there is little risk of a net cost to the federal government. One reason is that the line serves a known renewable energy resource area, for which major new wind generation construction seems nearly certain if adequate transmission is provided. This is a situation of "if you build it, [they] will come."[65] A major benefit to generation developers is that they do not have to prefund the construction. Federal borrowing authority is used to finance the upgrades with BPA recouping the funds through transmission rates over time. BPA can reasonably count on developers, or their power offtakers, to purchase

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[60] American Recovery and Reinvestment Act of 2009, Div. A, Title IV, § 401.

[61] BPA agrees to build network upgrades sufficient to provide delivery service for the output of their plants at a rolled in (postage stamp) transmission rate applicable to all BPA customers. In BPA parlance, these agreements are called Precedent Transmission Service Agreements. *See* Bulletin: 2009 Network Open Season, Version 2 (June 23, 2009), *available at* http://www.transmission.bpa.gov/includes/get.cfm?ID=1496.

[62] BPA reserved the right not to build and to release the customer's security, if BPA ultimately concluded that the criteria by which it judged projects was not satisfied.

[63] *See, e.g.,* Letter from Bonneville Power Administration to Customers, Constituents, Tribes and other Stakeholders (May 28, 2010), *available at* http://www.transmission.bpa.gov/customer_forums/open_season_2009/2009_NOS_decision_letter_final.pdf. It should be noted that the Network Open Season also allocates transmission service that is available from existing facilities in a more efficient manner than was used historically. In 2008 another 2,200 MW of transmission service was allocated and sold through this process. BPA plans to hold a Network Open Season at least annually.

[64] *See* Bonneville Power Administration, Transmission, http://www.transmission.bpa.gov/PlanProj/Transmission_Projects/default.cfm?page=MJD (last visited Aug. 10, 2010).

[65] The 2009 Network Open Season resulted in the sale of another 1,100+ MW over transmission upgrades designated to be built as a result of the 2008 Open Season. BPA May 28, 2010 Letter to Customers, *supra* note 63.

use of the full line capacity, even if each individual developer cannot know in advance if it will be a successful party needing to use the line.

Building on its success with McNary-John Day and the 2008 Network Open Season, BPA has initiated an annual open-season approach to promote development of economically beneficial regional transmission upgrades. This approach has broken the bottleneck on transmission expansion on BPA's main grid to some extent and is key to continued development of renewable resources in the Western portion of the Pacific Northwest.[66]

The Western Area Power Administration Takes the Next Steps.

The ARRA, in addition to providing BPA with additional borrowing authority, also extended an additional $3.25 billion in borrowing authority to the WAPA.[67] In response, WAPA has initiated an open public process to develop a Transmission Infrastructure Program to most efficiently use these funds made available to it. Of the stated goals of the Transmission Infrastructure Program, two are to (i) construct and/or upgrade transmission lines to deliver renewable resources to market, and (ii) leverage borrowing authority by partnering with others.[68]

The response to this program has been overwhelming: WAPA received over 200 proposals from transmission developers and is in private negotiations with several of them.[69] In addition, WAPA has announced a partnership with the Montana-Alberta Tie line, a 214-mile, 230 kV merchant transmission line between Great Falls, Montana and Lethbridge, Alberta,

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[66] BPA's service territory extends to the continental divide and includes portions of Montana and Wyoming, but its main grid is concentrated in Oregon, Washington, and Idaho. It remains unclear, however, whether BPA will be able to adapt this new open season approach to development of longer interstate transmission lines to access Montana and Wyoming wind resources for the Northwest population centers. The Montana Intertie is paid for by a separate transmission rather than rolled into the BPA postage stamp rate for its main grid. This fact changes the economics of any open season significantly. Moreover, the remote wind resources, while higher quality than those in the Columbia Gorge, tend to be located just outside BPA's statutory service area in Montana and even farther east from the BPA territory in Wyoming.

[67] American Recovery and Reinvestment Act of 2009, Div. A, Tit. IV, § 402. Even before the infusion of federal dollars through the ARRA, WAPA used its federal authority to facilitate transmission upgrades to reinforce Path 15 in California. Path 15 had been heavily congested and blocked efficient market trades between the Northern and Southern portions of the state. This constraint aggravated the market distortions during the California energy crisis in the early 2000s. WAPA, with significant political encouragement from the executive branch, stepped in to form a unique partnership with an independent transmission company and a California utility to provide support critically needed to allow the project to move forward. *W. Area Power Admin.*, 99 FERC ¶ 61,306 (June 12, 2002). WAPA completed all planning work, acquired land rights, and managed construction and would own the transmission line and receive a 10% share of the transmission rights. The independent transmission company provided approximately 72% of the funding. The three parties involved in developing Path 15 turned operational control over to CAISO. Path 15 Upgrade Project (June 1, 2004), *available at* http://www.wapa.gov/sn/ops/transmission/path15/factSheet.pdf. This public/private partnership was unique and WAPA did not continue to play a pivotal role thereafter until the enactment of ARRA.

[68] *See* Western Area Power Administration, Western's Recovery Act Programs, Transmission Infrastructure Program, http://www.wapa.gov/recovery/programs.htm#prin (last visited Aug. 10, 2010).

[69] *See* Western Area Power Administration, Where's we've been, http://www.wapa.gov/recovery/timeline.htm.

Canada. FERC approved the financing, finding that it was a "just and reasonable way to advance the project" to the construction phase.[70]

This program incorporates some promising features, and also shows how responsive the market can be to a federal solution that achieves maximum benefit at minimum cost risk to the federal government. WAPA's partnering with private parties allows the authorized amount of borrowing authority to go much further than if used by WAPA simply to build its own projects. In addition, the economic feasibility and cost recovery principles WAPA applied to projects seeking funding help assure the federal government of obtaining maximum economic stimulus and transmission system benefit, at zero or low long-term federal cost.[71] The program, however, is inadequate in scope to facilitate the types of transmission interstate highways that would make best use of existing transmission corridors, and truly integrate the vast renewable energy potential of the Intermountain West and Southwest with the major load centers.

FERC's June 17 Proposal for Interregional Cost Allocation.

This concern remains for the next several years[72] at a minimum even if FERC adopts new rules similar to those proposed in its June 17 NOPR on interregional cost allocation.[73] In addition, we are concerned about the ability of FERC to implement its protocols in the WECC area. FERC proposes to require regions to adopt interregional transmission plans and to address cost allocation between each pair of regional transmission planning regions for projects in the interregional plan. Costs are to be allocated in a manner roughly commensurate with the estimated benefits to a region and meeting public policy requirements such as renewable energy standards or carbon reduction targets may be considered in identifying beneficiaries. "[A] cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, would not satisfy [FERC's] proposed principles for interregional cost allocation."[74]

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[70] *Montana Alberta Tie Ltd.*, 129 FERC ¶ 61,154, P 14 (Nov. 19, 2009).

[71] *See Western Area Power Administration Transmission Infrastructure Program,* 74 Fed. Reg. 22,732, 22,735 (May 14, 2009).

[72] If FERC acts reasonably quickly in reviewing comments and issuing a final order, considering rehearing petitions and issuing the likely clarifications or modifications, and retains its one-year window for neighboring regions to establish interregional planning and cost allocation protocols, the protocols will probably be filed at the end of 2011 at the earliest and possibly nearer the end of first quarter 2012. Then FERC will need to review the compliance filings and rule on them. This could easily take six to nine months, with a final order issued in late 2012. If neighboring regions do not agree, of course, the process will be delayed while FERC conducts a paper hearing and issues a default order for interregional cost allocation, which would almost certainly be subject to rehearing and possibly challenge in the circuit court. Once the planning and cost allocation protocols are in place, any proposals for such interstate transmission highways will need to be studied and a decision made as to what if any proposals make it into the interregional plan. Next the cost allocation analysis will need to be applied to the proposal(s) and any challenges to the application of the new protocol must be resolved. This process could easily take four or more years to complete. This delay, combined with the long time frame for permitting multi-state projects, could well stall development of high quality renewable resources for years and contribute significantly to a failure to meet renewable energy standards and carbon reduction standards on the West Coast.

[73] June 17 NOPR, *supra* note 17, ¶¶ 170-77.

[74] *Id.* ¶ 175 n.173.

If neighboring regions within the WECC fail to come to agreement and submit voluntary cost allocation protocols in a timely fashion, FERC has announced that it will use its authority to remedy undue discrimination to impose a cost allocation scheme on the non-complying regions. FERC cites examples of prior use of its authority to allocate the costs of jurisdictional transmission facilities to beneficiaries "whether or not those beneficiaries have entered into a voluntary agreement with the public utility that is seeking to recover those costs."[75] Yet, FERC also cited its authority to remedy discrimination as the basis for Order 2000, which required public utilities to attempt to form RTOs and used its "bully pulpit" effectively to promote RTOs in many areas of the nation. However, as much as FERC favors RTOs, it has never taken the step of purporting to impose an RTO on entities that failed to agree voluntarily to join one.

In fact, FERC would not or could not impose RTOs on utilities under its current legal authority. The same may well be true of interregional cost allocation protocols: the direct authority of FERC to impose costs on specific utilities lies in the right, pursuant to Section 205 of the Federal Power Act, to set rates for use of transmission facilities for wholesale power transactions. FERC also cites its authority under Section 206 to remedy undue discrimination, but that authority is derivative of its rate-making authority. However, most of the revenues that pay for transmission facilities in non-RTO areas are collected in retail rates not set by FERC, for the use of transmission lines to serve native retail loads of utilities. Therefore, FERC's protocols can succeed only if the courts find upon appeal that FERC has the statutory authority to set general regional transmission cost allocations and then to require state utility regulators to pass a general FERC transmission cost allocation through to retail rates.[76] In recent years, the courts have been unwilling to affirm FERC's right to impose arguably lesser expansions of its authority over transmission facilities.[77] Moreover, we are not aware of even alleged authority for FERC to impose such requirements on municipal utilities, public utility districts, people's utility districts, or Rural Utilities Service-financed cooperatives, which constitute a major portion of Western utility retail loads. Thus, as a practical matter, policymakers must assume implementation of FERC's cost-allocation requirements for interregional projects in the WECC will be difficult at best. Accordingly, advocates of a clean energy future and policymakers should continue to look for alternatives—such as federal participation in right sizing high-priority transmission projects to access remote renewable resources—if they wish to see the West meet existing renewable resource standards and carbon reduction targets.

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[75] *Id.* ¶ 145. The examples provided are rate proposals to address unauthorized use of a transmission system as a result of parallel flows and cost allocation requirements for MISO and PJM when one develops facilities in its footprint that benefits entities in the other's footprint. *Id.* ¶¶ 143-44.

[76] This problem of needing to compel state action in non-RTO areas does not mean that FERC's enforcement ability is assured in regions with RTOs. As seen in recent MISO negotiations and filings, if state utility regulators are dissatisfied with transmission cost allocations, they can exert pressure on utilities to withdraw from the RTO rather than accept the cost allocation. *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,060 (Oct. 23, 2009).

[77] The Energy Policy Act of 2005 added Section 216 of the Federal Power Act to give FERC the power to issue permits for the construction or modification of electric transmission facilities in areas designated as national interest corridors by the Secretary of Energy. In February 2009, the United States Court of Appeals for the Fourth Circuit ruled that FERC may only step in to exert that power when a state commission has withheld approval of the permit application for more than one year, and not when a state commission has denied the permit application. *Piedmont Envtl Council v. FERC*, 558 F.3d 304 (4th Cir. 2009). The decision thus upholds a state commission's right to halt a transmission line project without fear that FERC will later preempt that state's decision.

Summary of Experience Under Open Access.

As noted above, transmission gets built only if its developers have a strong assurance that they will be compensated. For these reasons, sponsors can be expected to opt to scale transmission projects to meet, but not exceed, the amount of advance subscriptions initially available. Comparable disincentives exist for retail utilities, which must show current "need" for the facilities in seeking regulatory recovery of the cost of such facilities and for merchant transmission providers, who must show the ability to pay their investors from the time the facility goes into service. Even in RTO regions, issues related to allocation of costs of initially unused transmission capacity often create substantial delays, and even paralysis, in getting right-sized new facilities constructed.[78]

Under our current system, successful transmission expansions generally require the ability to fully subscribe the new capacity before proceeding to construction or a cost-allocation scheme that allows spreading the cost of uncommitted capacity over a large group of ratepayers who will receive future benefits. There is no existing structure in the WECC that would permit interconnection-wide cost allocation. Thus, our current policies and regulatory structures are inadequate for the task of constructing an interstate transmission system to access our highest quality renewable resources. Whether FERC's proposed new requirements will do the job will not be known for four to five years at best, and FERC's protocols are likely to face serious legal challenges. Advocates of a clean energy future and policymakers should consider a federally supported solution that could accelerate achievement of existing state regulatory requirements and facilitate national clean energy and carbon reduction goals.

REFLECTIONS ON A FEDERAL ROLE

The federal government can play an enabling role in bridging the revenue gap in order to facilitate the construction of right-sized transmission interstate highways. There have been several proposals for focused, new federal support for transmission expansion to access the most attractive renewable resources.[79] One approach would provide federal bridge funding for high

[78] For example, MISO continues to struggle with cost allocation for the Brookings Line, a 345 kV interstate transmission line proposed to run through a wind rich area to the Twin Cities area in Minnesota. FERC recently ordered MISO to remove the line from the generator interconnection agreements to a group of generators to which the costs had been 100% assigned. *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 FERC ¶ 61,019 (Oct. 9, 2009), *on reh'g* 131 FERC ¶ 61,165 (May 20, 2010). MISO is now restudying the generators' interconnection needs, and the projects are on hold again. (The initial studies took about five years; the restudy may take another year, but there is no certainty that the approach MISO is taking will not be challenged again at FERC thereafter. MISO filed a new cost-allocation filing on July 15, 2010, which proposed a new category of multi-value projects for which a major portion of the cost would be spread to customers throughout MISO. *See* Docket No. ER-1791-000. The Brookings Line dilemma may be resolved if the line qualifies for treatment under the anticipated new cost allocation proposal.) For the most recent documents related to MISO's current cost allocation proposal, go to the Regional Expansion Criteria & Benefits Task Force website at http://www.midwestiso.org/page/Committees, and select "Regional Expansion Criteria & Benefits Task Force (RECBTF)" from the "Active Committees" drop-down menu. The most recent documents can be accessed by clicking on the most recent meeting link.

[79] For example, MidAmerican Energy Holdings Company has proposed federal legislation to address the problem of allocation of costs impeding the most economic development of the nation's most attractive renewable energy resource areas. The proposal for bridge funding has also been supported in concept by the American Wind

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priority transmission projects identified in a clean energy future-oriented planning process. The bridge would be in the form of federal financing mechanisms by which the federal government could step in, upon request, and assume, or otherwise help mitigate, the up-front cost recovery risk associated with constructing new incremental transmission capacity that otherwise would not be built in the absence of up-front cost-recovery assurance given by a regulatory entity. Such incremental capacity would constitute only a small percentage of a transmission project's total cost and would provide great societal benefit. This paper has addressed the need for and value of such a federal bridging initiative.

The federal government has as a fundamental constitutional purpose to promote interstate commerce. One of the federal government's most successful ventures in this regard was the building of the interstate highway system. These vital enhancers of the national economy could not have been built without federal action and federal financing. In the case of transmission expansion, the federal government can achieve national goals through a program that provides up-front financial risk mitigation—rather than through a far more expensive federal construction reimbursement program funded by a user tax, as was required to achieve the interstate highway system.[80] As a practical matter, the federal government may be the only entity with the wherewithal to provide a solution. Indeed, it was the federal government that provided the financing to extend transmission to some of the West's clean energy resources—the Federal Columbia River Power System.

If the goals of energy independence and reduction of climate change are to be achieved and related state requirements are to be timely satisfied, such revenue-bridging initiatives are particularly needed. The most robust renewable resources simply are not located near major population centers, and the capacity of the transmission system to handle the necessary transfers of electric power is being exhausted in many parts of the country. In the meantime, some of our best resources remain undevelopable for lack of delivery capability.

Unlike the major federal cost required for the interstate highway system, the federal cost of enabling a robust interstate transmission system would be relatively modest. Private developers are willing to undertake the needed projects and share in the risks, if they can be assured that costs will be allocated in a manner that provides a reasonable return on the private

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Energy Association. This paper will not address the many details of any legislation that would implement this bridging concept, but instead has concentrated on the need for and value of such a federal bridging initiative.

[80] A "Highway Trust Fund" was established by a 1956 act of Congress to hold highway user tax revenue from which payments could be made to the states building the interstate highway system. Congress provided for borrowing in the form of repayable advances during the early years of the Trust Fund. However, the Byrd Amendment changed the approach to funding—limiting appropriations for a project to the amount of forecasted tax from the improvement. U.S. Dept. of Transportation, Federal Highway Administration, America's Highways 1776-1976: A History of the Federal-Aid Program 474 (1976). Thereafter, the Interstate Construction Program, like the federal-aid highway program of which it is a part, operates on a reimbursement basis. After the Federal Highway Administration (the "FHWA") authorizes a state to proceed with a project, the state pays the bills for eligible activities, and then submits bills to the FHWA, which reimburses the state for the federal share. The FHWA makes a commitment (or "obligation") to reimburse the federal share. *See* U.S. Dept. of Transportation, Federal Highway Administration, Frequently Asked Questions, http://www.fhwa.dot.gov/interstate/faq.htm# (last visited Aug. 10, 2010).

efforts and investments. In turn, we know with some confidence that if a properly designed transmission interstate highway system is built connecting major renewable resource areas with major load areas, that system will be used and thus paid for—state and possibly federal renewable portfolio standards should assure a demand for the facilities.

A federal role in assuring the recovery of investments in such systems is a crucial enabling step, but it can be a relatively short-lived burden to the federal government, and can be structured so as to involve relatively little financial risk in the medium- or long-run to the federal treasury. But it is important to move forward expeditiously if federal participation is to result in completion of a right-sized, interstate transmission highway system to access the most attractive renewable resources in the West. At this time there are an unprecedented number of transmission projects already proposed throughout the Western U.S., including the Mountain State Transmission Intertie, Chinook, Zephyr, Wind Spirit, and others. These projects are backed by willing investors ready to move forward if the projects can be financed. Determination of whether these projects or some combination of them are right sized is outside the scope of this paper. But, it is plainly a subject for advocates of a clean energy future and policymakers' immediate consideration, and the funds for doing so may, to some extent, be available from the ARRA. To the extent these projects are appropriately sized, the development of an interstate transmission highway could be facilitated and expedited if a federal role in assuring the initial recovery of right-sized investments were put in place.[81] This near-term "federal solution" could be accomplished while regions experiment with longer-term solutions under FERC's guidance. Without question, advocates for a clean energy future should continue to encourage FERC to use its authorities, such as they are, to promote interregional cost allocation and recovery plans that will promote renewable energy and carbon reduction. And FERC may be able to forge voluntary solutions to these critical issues over time. But, absent consideration of the federal bridge funding solution, however, we may well see development of high quality renewable resources in the West stalled for years to come.

[81] Failure to act expeditiously also presents the risk that projects will be smaller than they would be if economies of scale were captured. If that is the case and such projects are built, valuable transmission corridors will be used in an inefficient manner and the West will lose the advantage of right sizing its transmission expansion.

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