TRANSMISSION ISSUES FOR THE POWER PLAN

INTRODUCTION

The electrical transmission system of the Northwest is not broken, but it is clearly showing signs of strain. For several years now, the region has been locked in a struggle between the advocates of regional transmission organizations, which entail a substantial redesign of the institutions and rules for planning, building and operating the transmission system, and those who favor something very close to the status quo. The result has been gridlock. The region is stuck in an intermediate state, unable to return to a fully regulated electrical system, and unwilling to undertake the changes needed to ensure a well functioning restructured electrical system. We are trapped trying to make an inadequate transmission system serve changed and changing needs.

Ironically, this is a worse situation than either of the polar positions. Uncertainty about the ultimate organization of the industry is delaying needed institutional reforms and needed investment in both generating capacity and transmission system upgrades. Generating plant location decisions and electricity demand decisions are being made with limited regard for the transmission system costs that are implied. The region's inability to move in one direction or the other is likely to lead to future reliability problems and economic penalties.

The Council's interest in these issues stems from its charge to assure an adequate, efficient, economical and reliable power supply for the region. The primary purpose of this paper is to build an understanding of the kind and severity of the problems facing the region's transmission system. Secondarily, it proposes some principles for improving the regional transmission system for the purpose of regional discussion. The region has expended untold hours attempting to devise a solution that would satisfy the requirements of the Federal Energy Regulatory Commission (FERC), be effective in addressing the real problems, and be able to garner the support of a critical mass in the region. To date it has been unsuccessful in at least the latter objective. There is now an effort to devise and evaluate a spectrum of alternative approaches to the region's transmission problems. Many are hopeful that this process will lead to alternatives that are sufficient and workable improvements in how the region addresses transmission issues, and also are supported by much of the region. The Council staff supports this effort. However, the key phrase is "sufficient and workable improvements." There is little sense in developing a consensus around solutions that are inadequate and/or unworkable.

This paper was developed by the staff of the Northwest Power and Conservation Council. The objective is to help move the region toward improvements in the operation and organization of the transmission system. The paper does not necessarily reflect the views of Council members, but rather is a vehicle for the Council to explore transmission issues with the region.

DESCRIPTION OF THE PROBLEM

An electrical power system requires constant, second by second, management of electricity generation and transmission to match electricity demands. Transmission system operators are primarily responsible for this delicate balancing of supply, demand, and transmission capability. The system is operated for two primary objectives, the security or reliability of the physical system, and the economy of the system. Thus, from an operational perspective, it is the transmission system operators that are responsible for achieving an efficient, economical, and reliable power supply. Transmission system operation and control, therefore, are central to the issues in the Council's power plan.

Over the last 30 years, changes in the basic structure of the electricity sector have created challenges to the traditional operation of power systems. Changes in the technology of electricity generation have gradually led to the opening of electricity generation to more competition and to a weakening of the rationale for monopoly electricity generation by vertically integrated utilities. The changes began with policies designed to require utilities to purchase energy from renewable and high-efficiency customer-owned generating resources. These resources tended to be smaller in scale and lower in capital requirements than the then dominant coal and nuclear plants. Ultimately, as technology continued to improve and electricity generation by independent parties proved increasingly competitive, Congress and the Federal Energy Regulatory Administration began taking actions to further facilitate this competition. Today independent generators play a significant role in electricity supply and independent power producers have developed most of the recent and proposed new generating plants.

The growth of independent power generation has become increasingly incompatible with the traditional electricity system operation by individual control area operators, usually affiliated with regulated utilities and their affiliated merchant generators. The issue now is how utilities, independent power developers, transmission owners, load-serving entities and even consumers make coherent decisions about what to build and where to build in a vast interconnected and interdependent system. Those decisions can have significant consequences in terms of the costs to consumers of the region, the distribution of those costs among various parties, the adequacy and reliability of the power supply, and the quality of the environment. It has become clear that the way in which the electricity industry has evolved is straining the existing transmission system, both in a physical sense and in the way the system is managed, and that significant changes are needed.

Several problems that have been observed in the Western electricity grid are described in the table below along with their effects on the adequacy, reliability and efficiency of the power system. These problems are described in more detail in Appendix A to this paper.

Problems	Consequences
A disconnect between the commercial basis of energy transactions (contract path) and the actual power flows that they cause on the transmission system.	• Increasing difficulty in managing unscheduled electricity flows over transmission lines leading to increased risks to electric system reliability due to unexpected real time operational requirements. • Inefficient management and resolution of short-term transmission system congestion resulting in decreased efficiency and inequitable impacts on other parties. • . • Reduced efficiency and economy of the power system, lack of incentive for potential demand-side response to congestion.
Competitive advantages of control area operators over competing generation owners.	• Discriminatory access for non-control areas • Proliferation of control area operators, causing increased fragmentation of the operation and management of the power grid • Decreased efficiency and increased operating costs.
Transaction and rate pancaking, i.e. contracting and paying for the fixed costs of multiple transmission segments on a volumetric basis to complete a power sale.	• Higher transactions costs • Complicated contracting processes • Inaccurate price signals, resulting in inefficient utilization of transmission and generation capacity.
Limited access to available transmission capacity in the medium term.	• Inefficient utilization of existing transmission and generation capacity.
Inability to monitor wholesale electricity market, identify market power abuse or provide mitigation and accountability.	• Potential market power abuse, restricted competition, reduced efficiency, increased potential for price volatility.

Lack of clear responsibility for system expansion and confused incentives to do so.	• Failure to invest in needed transmission expansion or alternatives leading to decreased reliability • Inefficient system expansion, more costly mix of transmission, generation and demand response leading to higher electricity costs to consumers. • Fragmented decisions regarding transmission expansion, no entree for demand-side solutions to capacity problems.

Utilities and others in the region have recognized this growing list of problems and several forums have organized to study the problems and work toward solutions. Appendix B describes some of these groups and their scopes of work. The changes required to solve these problems can be large and extremely complicated. They raise issues of state jurisdiction over transmission systems that have resulted in strong resistance in some states and challenges to various FERC proposals, including that for a standard market design. They raise equity issues among utilities and transmission owners who are concerned that they could be adversely affected by changes in the operation and pricing of transmission systems. In addition, the nature of the Northwest's hydroelectric system creates special challenges that would have to be accommodated in any electrical market structure for the region. There are efforts in the region to try to identify incremental steps that can be taken and that may resolve some of the problems.

There are some in the region that believe the current system of transmission management is working well. But the problems listed above, and further explained in Appendix A, argue that it is severely strained. The region needs to resolve these problems. There are a variety of successful experiences that can be built upon and adapted to Northwest conditions, and a variety of failed experiences that need to be avoided. The next section proposes for discussion some basic principles that should guide the design of a regional transmission system.

PRINCIPLES FOR ADDRESSING THE ISSUES

There are several principles that should characterize a well-functioning transmission system. They include reliable and economical operation of the power system, open and non-discriminatory transmission access, incentives and procedures to efficiently manage transmission system congestion, adequate safeguards against the abuse of market power, and clear lines of responsibility for rational expansion of the transmission system. These principles are described further below.

Reliable Operation of the System

The key principle is that the operational reliability and security of the power system be maintained. This requires active, continuous, management by the transmission system operators. Transmission system operations are organized into "control areas," of which there are 13 in the Northwest. Some control areas are quite large, e.g., Bonneville and PacifiCorp (which has two), and some are relatively small, e.g. Grant County PUD. System operators must continuously balance electricity demands and generation while keeping power flows over individual lines within and between control areas within specific limits for system operating reliability. Those operating limits are set based on maintaining flows on the rest of the system within safe limits in the event of any of a number of outages on key parts of the system -- either generators, transmission lines or other transmission hardware.

Maintaining operational reliability is a complex task. Power flows from each generator over the entire transmission network in inverse relationship to the impedance[1] of the individual lines on the system. Given a particular configuration of generation and demand, power flow over the network is determined. It is not controllable and cannot be directed to one or another specific transmission line, except for specific limited cases. Operators manage the system and maintain it within reliable limits by modifying the operating levels of generators (redispatching them) from those operating levels that would otherwise be chosen by their owners based simply on their load obligations and on opportunities in the energy market. Transmission system operators also have various pieces of transmission hardware that they can operate to help maintain the transmission system within reliable operating limits.

If there is an outage of any of the key pieces of the total system, the remaining system must not be put into an unstable position by the instantaneous redirection of all the power flows on the system that might lead to system collapse before remedial action can be taken. Generation is dispatched in a pattern that will avoid these problems in the case of the first contingency (e.g., the loss of a major transmission line) encountered by the system. This is called a "security-constrained dispatch." However, these arrangements are not foolproof. A good example of the results of a failure of such operational requirements was provided by the Midwest and Northeast blackout on August 14, 2003.

The management of the regional electricity grid must ensure that operational reliability requirements are met in the context of the current electricity market with its growing diversity of suppliers and increasing numbers of transactions. The existing system of transmission and distribution lines has developed over time as the region has grown. Thus it reflects traditional patterns of generation and loads. These patterns have changed rapidly in recent years, and that is likely to require changes in the existing transmission system and its management.

The growing merchant generation presence makes the management of the transmission system more complex. On the one hand, we have the existing commercial system for wholesale

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[1] Impedance is the AC analog of resistance in a DC system and can be thought of similarly. Roughly, large, high voltage lines have low impedance and small, low voltage lines have high impedance.

transactions that is largely based on the concept of "contract paths". For example, a generator may sell to a utility or consumer at a distant location. In order to move the power to the customer, the generator would have to buy capacity on a single end-to-end set of transmission lines between his generator and the customer's location. The transmission capacity purchased defines the contract path. On the other hand is the fact that actual power flow patterns will differ from the contract paths and that these actual flows are shifting much more frequently and unpredictably than in the past. The effects of this discrepancy will be discussed further in the Appendix A. In essence, it complicates the physical operation of the transmission system and disconnects the commercial side of the operation from the physical operation.

This principle of reliable operation would imply a need to schedule transactions based on actual power flows, rather than contract paths. This would help reduce surprises that arise from unscheduled power flows. In addition, given the reality of the increasing volume and complexity of transactions, a more centralized coordination of the system, as opposed to multiple control areas, should increase the ability to deal with any problems that do arise more quickly and efficiently.

Economical Operation of the System

The economic part of the dispatch problem is ensuring that the security constrained dispatch is also the least cost dispatch, that is, that the most economic resources are running to meet the load at any given time, subject to the transmission constraints. Historically in the Northwest, this was a relatively simple problem: the coal and nuclear plants were base-loaded and their operation did not vary significantly from hour to hour, and the load swings were carried on the hydro system. This problem is becoming more complex with the emergence of the merchant generator sector that largely operates combined cycle plants and aims to sell into multiple western markets.

Economic efficiency of the electricity dispatch is not inherently a transmission system operator's responsibility. It is the role of the electricity wholesale market to achieve economic efficiency, but the transmission system must create many of the conditions under which economic transactions can occur. The wholesale market's role is to facilitate transactions among generators and consumers of electricity and the transmission system is their connection to one another. Economic efficiency is most likely to be achieved in a market characterized by open access, consistent rules and easily accessible information on prices and the bids of other suppliers and consumers. This is, in a sense, an umbrella principle that requires satisfaction of the other principles in order to be realized.

Electricity trading is currently being done through the bilateral and spot markets in the West. However, in most successful electricity markets some type of more formal market has been instituted. Such markets are typically operated by the transmission operator and, at a minimum, include real time imbalance markets and redispatch markets for transmission congestion management. The transmission operator is the entity that has the necessary overview of the dispatch and reliability issues to successfully perform a market facilitation role and to integrate the physical and commercial aspects of the market. In addition, the transmission operator is in a good position to provide market information and data in a timely manner. The transmission operator also has access to the data that is necessary to monitor the competitive behavior of the market and guard against market power abuses.

The current system that results in rate and transaction pancaking is an obstacle to more efficient operation of the transmission system. Not only does pancaking add complexity and transaction costs (e.g. interaction with more than one OASIS), but it produces inefficient price signals by introducing fixed costs into the operational decision of market participants. Economic efficiency would require that short-term decisions of buyers and sellers be based on variable costs only.

Open and Non-discriminatory Access

The transmission system is the path that connects electricity generators and consumers. Open and equal access to that path is essential for achieving an economical power system.. The transmission system is, given current technology, what economists call a natural monopoly service. That is, it is most efficiently provided by a single entity over a single set of wires rather than by competing entities. This is a function of economies of scale in the technology, and of the demanding physical control requirements of electrical systems. Because transmission is a monopoly, open and non-discriminatory access to the transmission system is central to making electricity markets work efficiently. This principle has been the keystone of FERC's efforts to establish workably competitive wholesale electricity markets since Order No. 888, in 1996. This principle may require that transmission operation be under the direction of an independent organization.

Transmission system access has, to a large extent, been achieved in the Pacific Northwest and in the West. There are few public concerns about overtly discriminatory behavior on the part of transmission owners favoring their own affiliated generation. However, the existing process for promoting the trading of available transmission capacity has not proven effective in promoting some types of transactions. This argues for transparent and liquid platforms for buying and selling transmission access as well as energy and capacity. In addition, at present no information is generated that provides a measure of the value of system capacity expansion, or conversely the value of demand reductions or generator locations in particular areas. As a result, neither the responsibility for, nor the incentives for, addressing transmission problems is clear and the resulting inaction is likely to lead to reliability problems. This leads to the next principle.

Clear Responsibility and Incentives for Efficient Transmission System Expansion

The responsibility for expanding the transmission system, and the incentives for doing so, are unclear at the current time. It is generally acknowledged that the demands on transmission systems have been growing more rapidly than the capacity of the systems. This poses significant risks to the reliability of the power grid. There needs to be clear responsibility for maintaining and expanding the transmission system efficiently and any monopoly entity with that responsibility needs to be clear from commercial conflicts of interest. This is argues for independent governance of the transmission system.

Efficient system expansion implies that the expansion of the system is based on meeting demands with the lowest cost means, whether transmission additions, modified generation locations or demand-side measures. These outcomes are generally most easily achieved in a system where decisions are based on appropriate prices rather than made administratively. When necessary for other reasons, administrative decisions about system expansion can be made in a way that approaches market outcomes in limited ways, depending on the rigor of the process, but it is typically a second-best kind of solution. This also argues for transparent and liquid platforms for buying and selling transmission access as well as energy and capacity.

Effective Management of Transmission Congestion

Congestion can occur on the transmission system when the power flows from proposed or actual schedules are higher than allowed by operating reliability limits, or more loosely, when proposed schedules are greater than the scheduling limits. Since, as discussed above, schedules and power flows are not the same, there may well be discrepancies between these two characterizations of congestion. The power flow definition is the one that is most realistic.

Economic efficiency in the context of the management of the transmission system implies that mechanisms exist to allow the highest valued transactions to go through. Since the capacity of the system is limited and market participants may hold pre-existing rights, economic efficiency implies that there is a liquid market for voluntary trading of transmission rights. A liquid market would require easily accessible information on transmission system conditions based on actual flows and a trading platform to facilitate trades.

Market Monitoring and Evaluation

Active market monitoring is important to making the current hybrid regulated/deregulated energy market work successfully. The transitional nature of these markets has resulted in vulnerability to poor market designs, misplaced incentive structures and exploitation of the markets in unintended ways. The nature of electricity markets, at least for the foreseeable future, will likely result in cases of significant market power under some specific conditions. Transmission congestion can contribute to these conditions. While the current transmission management system in the West largely does not have the kinds of problems that need additional transmission market monitoring, any significant changes to the structure to address some of the problems described below should be accompanied by enhanced monitoring to ensure that the kinds of problems seen in the energy market do not develop in the transmission markets.

If the wholesale electricity market becomes more integrated with operation of the transmission system, as has generally been the case in most successful wholesale markets, the transmission system operator becomes the logical entity to monitor and evaluate the wholesale electricity market, as well as the transmission market. If a central transmission operator is to serve this role, it is important that this entity be independent and free from commercial conflict of interest.

REQUEST FOR COMMENTS

The staff has argued in this paper that there are problems building in the regional transmission system. To most citizens, transmission problems will not be apparent until there is a failure of the entire system as occurred in the East and Midwest on August 14, 2003. However, those entities responsible for the hour-to-hour operation of the transmission system are aware of the growing problems and have been actively working to find solutions.

This paper has proposed a set of principles that should guide changes to the management of the transmission system. The Council would like to hear from the region regarding these principles and possible changes to the management of the transmission system that could satisfy these principles, or others that are believed to be important.

- Are there other principles that should be considered?
- Are there intermediate steps the region could take to alleviate some of the transmission problems and satisfy some of the principles?
- Should the principles enumerated above be included in the Council's power plan?
- Should the Council go beyond listing principles and recommend regional policies on transmission in its power plan?

APPENDIX A

PROBLEMS CURRENTLY FACING THE TRANSMISSION SYSTEM

The discussion above alluded to a number of general problems that face the Northwest's transmission system. These problems apply, as well, to the western system as a whole, because the Northwest's system is not physically distinct but, rather, is part of the larger western system both physically and institutionally.

Some of the problems are well recognized and are being addressed in various forums. Appendix B of this paper describes some of the efforts underway in the region and the broader West. Some of the problems are not being addressed well currently. This section describes the developing problems is more technical detail.

The issues are broken into three sections: Operations-related, expansion-related, and market monitoring.

SYSTEM OPERATIONS: RELIABILITY, ACCESS, AND EFFICIENCY

Contract Path vs. Power Flow

One of the central issues for the commercial operation of the transmission system is managing a set of commercial transactions that only partially reflect their actual impact on the underlying physical system. This has a direct influence on the ability of system operators to maintain the reliability of the transmission system. Beyond that, however, there are implications for the ability to maintain a liquid market for shorter-term access to the system and for the ability to manage congestion on the transmission system efficiently, which will lead to the most efficient use of the system overall. This section addresses the reliability issues raised by this commercial system.

The problem exists because most wholesale contracts are point to point, path-specific contracts, which do not take direct account of the network characteristics of power flows. The related power flows that are caused by these contracts, but are not on the contract path are called unscheduled flows (also called loop flows or parallel flows).[2]

Current transmission management approaches using these contract path rights on rated paths in the West, including the Northwest, have now and will continue to have problems. Unscheduled flow problems on several of the paths on the major transmission loop in the West are becoming increasingly difficult to manage under the current regime. Currently, these problems are managed through the Unscheduled Flow Mitigation Plan (UFMP) of the WECC.[3] The UFMP requires a series of steps, beginning with accommodation by the path owner through restrictions

[2] Native load service, like an IOU's service to its retail load, as well as most Bonneville service to its wholesale power customers, is network service, which does not specify particular paths.
[3] Western Electricity Coordinating Council, formerly the WSCC.

on its own schedules, followed by the operation of phase shifters on the system, and ending with curtailment of schedules on other paths that contribute to loop flow on the affected path.

All of these actions have to take place in real time, because it is only then that operating problems due to loop flow become apparent. This leads to potential problems for system reliability. The real time problem occurs, because, while paths were given scheduling limits during the path rating process that accommodate typical levels of loop flow, changing generation patterns will change the actual flow patterns. These changes are not signaled by commercial schedules because actual flows differ from contract path schedules. This problem on the major Western transmission loop was particularly prominent during 2001 because of the unusual generation patterns caused by the drought in the West. However, it is likely to remain a significant problem because of the interest of new merchant generators in being able to serve seasonal markets all over the West, rather than focusing on just traditional service to load in a defined service area.

It is becoming increasingly difficult to properly identify the appropriate other schedules to curtail to get the desired effect. As a result, the problem falls back, by default, on the transmission owner whose lines are being adversely affected by the loop flow as the only way to maintain system operating reliability. Even when the UFMP works properly (that is, it cuts schedules that actually relieve the overloads), it is a non-market solution that cuts schedules using administrative rules that ignore transaction value, and that can leave recipients scrambling to replace cut supplies on very short notice. This problem is even more prevalent in the Eastern Interconnection, where it has led to the imposition of NERC's Transmission Loading Relief protocols. These protocols, which dictate which schedules are cut, are widely blamed for having exacerbated price spikes in Midwestern wholesale markets during 1998 and 1999. Whether, or to what extent they had an effect on the inability to control the recent cascading blackout in the Eastern Interconnection is not yet clear.

Parallel flow problems in the West and Northwest that are not managed under the UFMP, are also managed largely by curtailment (except in the California ISO). These curtailments are either done through agreements laid down in contracts or on a pro rata basis when no other rules apply. Many of the same problems arise under these agreements, and will become more difficult as the market is more heavily populated by merchant generators rather than vertically integrated utilities.

Without a larger regional transmission grid operator, it is almost certain that the current contract path approach and control area scheduling limits will be maintained. Path management will have to address the continued problems related to the discrepancies between contract path scheduling and actual power flows. Administration of the UFMP has already required new tools that indicate more clearly the actual flows from individual contract path schedules. This information will have to be available to control area operators on a timely basis, so that the appropriate schedules can be cut to achieve the desired effect within the required time (as little as 15 minutes, assuming no outages).

Some have suggested that the UFMP itself will eventually have to be renegotiated (if there are no regional transmission grid operators in the West) to allow for more market-based solutions to unscheduled flow problems. This would still address a more limited set of problems than a regional transmission grid operator because the UFMP only applies to a limited set of paths in the West, rather than being a system-wide solution to the problem, and still operates in real time only, which limits the ability of the schedule recipient to make economic responses to the schedule cuts.

In addition, Bonneville has recently proposed modifications to its definitions of rights under its network contracts. These modifications will make more explicit the flow basis of the network contract rights. Like the new tools for administration of the UFMP, these modifications will help to align the commercial system with the underlying physical behavior of the system. Similar modifications to Bonneville's point-to-point contracts, however, have not been made and the contract path commercial structure remains in place for those contracts.

Over the past several years, a new communication protocol, electronic scheduling or tagging (E-Tagging), has been introduced by National Electric Reliability Council (NERC) to replace the current system of schedule information transfer and verification across control area boundaries by phone and fax. Electronic scheduling has, and continues to be developed in response to FERC initiatives following on Order 888 and its OASIS requirements. NERC standards apply, albeit ultimately voluntarily at this point, to all transmission owners and control area operators, public and private.

E-tagging has gone through several iterations and the most recent version was put in place after suffering from extensive implementation problems. The problems were due in part to the number of entities (including each control area on the paths) that must deal with each tag before it is finally validated. E-Tagging is ultimately intended to allow both energy and transmission scheduling in a single joint electronic format. Nonetheless, it was designed for the 888 world of multiple control areas and contract paths and it does not, and will not, make the problems of contract paths and parallel flow go away, nor will it substitute for the simplicities of a single control area. The fact that in the Western Interconnection the mechanisms available to remedy system overloads have failed even in recent months to do their job (as cutting schedules simply led to changing schedules without changing the underlying generation pattern that was causing the problem) is cause for concern.

One of the apparent contributing elements to the recent blackout in the Eastern Interconnection was the large number of control areas (23) nominally under the direction of the Midwestern ISO, itself not a control area, but only a reliability coordinator. For reference, there are currently 16 control areas in the RTO West area (eleven representing the filing utilities, including BC Hydro) and approximately the same number in the rest of the West. The contract path system evolved in the context of the integration of individual, separated control areas, but it is not at all clear that a large number of control areas aids in the reliable operation of the transmission system, though, as will be discussed later, there are clear advantages to individual generation owners to have at least some of the functions of control areas.

If there were a large enough central transmission system operator, it would have the opportunity to essentially eliminate unscheduled flow problems because it could replace a commercial and scheduling regime based on contractually defined individual paths with one based on explicitly evaluating the power flows across the entire network, as defined by the points of injection of the power into and withdrawal of the power from the transmission system (sources and sinks). It could align the commercial system with the physical system. With appropriate coordination between similar entities in the West, loop flow from transactions with sources and sinks in other areas would also be eliminated as a reliability problem.

Such a change would, however, come at the cost of a major shift in the way commercial transactions are currently handled and would require conversion or translation of existing contracts having to do with the definition of transmission rights and business practices for scheduling.

The principles of reliable operation of the system and economic efficiency in congestion management are both applicable to this issue. The discrepancy between the contract path commercial system and the underlying physical behavior of the grid can lead to problems in managing the system to maintain reliability and to economically inefficient mechanisms to address the ensuing reliability problems.

Transmission Access

In addition, there are access problems because transmission capacity may go unused in the short term[4] when there is no long term Available Transmission Capacity (ATC) available, or because limitations on scheduling between control areas do not accurately represent the actual flow constraints on the paths and so artificially limit ATC. Analysis and surveys done in 2000 for the three previous operating seasons, as part of the joint Regional Transmission Associations' *Western Interconnection Biennial Transmission Plan*, and more recently for the westwide planning effort under the auspices of the Seams Steering Group – Western Interconnection (SSG-WI) indicated that there were substantial gaps between the effective Operating Transfer Capability[5] and the actual flow or net schedules on the line. This was the case despite a large number of the paths being examined having no ATC posted on OASIS[6] as available for sale. These problems have also been reiterated at recent meetings of the RTO West Regional Representatives' Group (RRG).

The study was not able to determine the cause of the gaps, though informal comments suggested that much ATC was not actively resold in secondary markets. Surveys done as part of the study attempted to confirm this suggestion with market participants' accounts of denial of access due to insufficient ATC, but were not definitive, partly because it was suggested that many

[4] This section addresses the inefficiencies in current approaches to getting access to existing capacity that is not being used as opposed to getting access through new construction, which is dealt with in the system expansion portion of the paper.
[5] OTC: a measure of path rating accounting for seasonal or other current operating constraints.
[6] Open Access Same-time Information System: an internet-based reservation and scheduling system required under Order 888.

participants did not pursue access after the initial posting of no ATC. These problems can prevent more efficient use of the existing transmission system and reduce competition in the electricity market.

The tools that are available currently appear to be inadequate to get the most usage out of the transmission system. There does not appear to be adequate liquidity in the secondary ATC market, despite apparent availability. This may have to do with the fact that the system of contract rights that is currently used is a system of physical rights to contract paths. "Physical rights" means that an entity that wishes to schedule use of the system must have the rights in hand to begin the process. Under the Order 888 open-access tariff, used by almost all transmission owners, there are two basic types of rights, firm and nonfirm, with rights in each category roughly equivalent in terms of priorities to service. Nonfirm service is typically provided on a very short-term basis, from hour to hour, as available.

The fact that there are only two gradations in the service order makes firm rights much more valuable to their holders, and they appear to be reluctant to sell them on a limited term basis (longer than hourly, but less than annually). The issue of gradations raises another apparent problem with the efficiency of the existing market for access. If a path is temporarily congested, for a limited number of hours, access to it can still be valuable if there is some way to deliver on the transaction in those times when the congestion exists.

The usual mechanism for this is redispatch of generation to eliminate the congestion or to allow the delivery to be made, albeit from a different generator, which would have to be paid for the service. This is the kind of mechanism historically used by vertically integrated utilities selling transmission service and using their own generation to enhance the ability to sell transmission (though in the old world probably not to the disadvantage of their own generation). The market mechanism for providing this service in an Order 888 world with administratively separated business lines appears not to have developed, with the consequence that generators that are not affiliated with transmission owners are at a disadvantage (since the transmission owner/operator can no longer automatically call on the affiliated generation to enhance access to the transmission system).

This redispatch market, which would increase the overall efficiency of the use of the transmission system, appears to be relatively limited as well as the secondary market for ATC. If there were a large central transmission operator, it could potentially facilitate or operate a redispatch market as part of its congestion management process that would substitute for the function, described above, that is no longer present.

For instance, a single transmission operator could eliminate the scheduling limits across paths that are imposed on transactions between control areas. Because a regional transmission grid operator would be a single control area, it would be able to manage flows to physical limits, rather than having to manage path-based schedules to (in some cases lower) scheduling limits. This would be likely to free up transmission capacity in a number of hours during the year, though not necessarily all of them.

More directly addressing the problem, a regional transmission grid operator would also be in a position to provide more effective long-term access for those periods (apparently much of the time for a number of paths) when the path usage is not up to reliability limits. It would be able to do this if the transmission rights were financial rights, the right to not have to pay congestion cost, rather than physical rights (the right to submit a schedule in the first place). Because they are not physical rights, entities that are not rights holders can submit schedules as long as they are willing to pay congestion costs, which could be minimal or non-existent frequently.

The corollary redispatch markets that would also part of a regional transmission grid operator's congestion management process would enable the regional transmission grid operator to manage these schedules while giving it the best set of tools to maintain the reliability of the system. These markets would also produce the locational price signals that will indicate to generators when it is profitable to operate, to transmission planners where it might be best to upgrade the transmission system, and provide incentives for demand side management solutions to some of the congestion problems.

In the absence of some sort of large central transmission operator, the mechanism for addressing this problem is not clear. The existing Order 888 tariff structure does not provide for the kinds of gradations of firmness in physical, contract path rights that would be necessary to replicate the financial gradations that can be accomplished with a financial rights scheme and active congestion management based on generator (and load) bids to redispatch. Even a more liquid short-term ATC market is unlikely to be able to provide such gradations. This issue raises the principle of open access and economic efficiency.

Advantages to Control Areas

A third issue is that there are advantages to operating a control area that are not available to entities that wish only to own generation. These advantages have to do largely with real-time imbalances. First, control areas enjoy a diversity advantage, in that control areas can net internal load and generation variations against each other to minimize the inadvertent schedule imbalances with other control areas. Individual independent generators do not enjoy that diversity advantage. Second, control areas are allowed to deliver subsequent net imbalance obligations in kind and at times other than when they are incurred, rather than paying for them at the then-current imbalance charge. This allows a control area, up to a limit, to "borrow" energy from its neighbors during expensive hours and repay it during cheap hours. Individual generators have to pay imbalance charges at the current rate to their host control area, when they have discrepancies between their scheduled and actual output.

One result of this competitive advantage is that in some parts of the country, now including parts of the West, merchant generators are forming new control areas encompassing only themselves (and their other affiliated generators). While there is no reliability advantage to this happening and additional control areas increase the complexity of scheduling and potentially the risks to reliability (the recent Eastern blackout may have been exacerbated by the complexity of the control area structure, encompassing 23 control areas), new entrants seek to gain some of the commercial advantages currently enjoyed only by control areas. There are currently no restrictions that prevent this from occurring.

With a regional transmission grid operator in place, all generators would be put on a comparable basis with regard to imbalance payments. It is unlikely that would occur absent the consolidation of control areas that a regional transmission grid operator would bring. This issue raises the principles of reliability, economic efficiency and open and non-discriminatory access.

Rate "Pancaking" and Economic Dispatch

Rate pancaking, the charging of multiple average volumetric transmission rates[7] to recover system fixed costs for transactions that cross service territory boundaries, is a bar to the most efficient operation of the generators. It introduces a fixed cost recovery element into transactions that might otherwise be economic on a variable cost basis, even though the fixed costs have already been incurred and cannot change as a result of the transaction going through or not. Long-term contracts do not typically face volumetric or transactional charges, since the cost recovery is set by other factors, such as contract demands or monthly or annual peak loads. But the short term and spot markets are affected and the effect is only partially mitigated by transmission rate discounting permitted under the Order 888 pro forma tariff.

A regional transmission grid operator would eliminate rate pancaking within its service territory, except for a charge to export that would, in addition to annual, monthly, weekly and daily fees, include hourly transactional fees. Without a regional transmission grid operator, rate pancaking would continue, unless eliminated under FERC's pro forma tariff. This issue raises the principle of economic efficiency.

Transaction Pancaking

In addition to the direct rate effects in doing transactions across multiple control area boundaries, there are other transaction costs that are incurred due to the complexity of having to deal with multiple control areas and multiple OASIS sites. These would be eliminated by a regional transmission grid operator. There could be an alternative solution to this issue through consolidation of the multiple OASIS sites and the full development of the electronic scheduling initiatives of NERC. This issue raises the principle of economic efficiency.

SYSTEM EXPANSION

Current Status and Issues

The original vertically integrated utility environment was one in which the decisions to invest in generation and/or transmission (and/or, with the introduction of least-cost planning, demand side measures) were integrated under one decision maker. The process was forward looking and made trade-offs of one investment against another as alternative means of meeting end-use load service requirements. Choices were made, for instance, between locating a coal plant at the mine mouth and building a long transmission line to reach loads, or building the plant closer to loads, saving on the transmission cost, but incurring the rail cost of bringing the coal to the plant.

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[7] Rates that are charged on a per unit of energy basis despite the fact that transmission costs are primarily fixed costs of capacity.

Utilities planned to build sufficient generation (or enroll sufficient interruptible demand) to meet projected peak loads with a high probability, under the eye of the state regulatory commission or local board.

This approach to planning and expansion of the system was built on a particular industry structure. That structure is, to a greater or lesser degree, depending on jurisdiction, being replaced by a different structure. Currently in the Northwest, as in the nation, most new generation is being built by third-party merchant generation companies for sales into the short-term market, for contract sales to load-serving entities, or both. (Seventy-one percent of the generation developed or to be developed between 1994 and 2003 in the Northwest is independently owned; 93 percent of that currently in permitting is IPP sponsored.)

These merchant generators, to the extent that they intend to sell into the wider market on a short-term basis, rather than contracting up front for the output of their plants, will only build when and where they see market opportunities and will not lock in construction decisions until necessary. Even if new merchant plants are built with long-term contracts for a major portion of their output, the problem remains that developers avoid making commitments to large capital investments until the last possible moment. At the same time, the load serving entities that might be signing these long-term contracts are also likely to be responding to market conditions, holding off when short-term prices are low and taking advantage of those markets.

This is a complication because with the decreased lead times to site and build new combined cycle plants, the lead time for getting a plant on line can be significantly less than the lead time for siting and constructing a major transmission line. The possibility of major technology changes, such as advances in distributed generation, increase the cost recovery risks posed to future transmission investment. This also increases the likelihood that there will be significantly more congestion in the future. Even if all new plants came with transmission upgrades that would eliminate congestion in the long run, those upgrades would likely lag the generation by 2-5 years. The result could be a more or less constant state of managing transmission congestion as new plants come on line.

At the other end of the system, parts of the Northwest have retail access, where some, usually large, end-use customers are not necessarily served by the generation affiliated with their distribution provider. This sets up active competition between the generation affiliated with the transmission owner and the third-party generation, not just for new wholesale markets, but for existing retail markets.

All of these changes have broken the institutional links that enabled integrated planning and decision-making about generation, transmission and demand side measures. Currently, transmission owners must respond to generator interconnection requests in the order in which they are placed, respond to requests for additional contract service from other entities than generators, or build to enhance service to loads that they serve through non-contract legal obligations (like native load service). This queuing process is extremely inefficient, and difficult for both generators and transmission owners. It does not provide for large-scale forward-looking transmission studies that might offer the information that would allow groups of generators to address system expansion problems in a way that any individual generator might not be able to.

There is, outside of the California ISO's control area, no explicit pricing of transmission congestion. As described earlier, congestion is generally managed in the forward markets through the presence or absence of ATC and the requirement for parties to have transmission rights in order to schedule transactions. It is managed in the real time markets by curtailments, either pro rata for firm rights (following non-firm curtailments) or pursuant to specific contract requirements.

Looked at for its implications on system expansion, this approach provides limited information for those considering alternative generation locations. (The access and operational issues are addressed above.) New generators get full information about the costs of interconnection at their location on the transmission grid only after they have waited their turn in the interconnection studies queue. The have little sense of the availability or costs of redispatch across constrained interfaces before they have to make decisions about location of their projects, so they are typically driven more by the relative costs of gas or other fuels at different locations than by transmission costs.

The transmission provider itself may make a decision about its willingness to redispatch (using its affiliated generation) around constraints on its system when it offers to provide access in the first place, though even that is difficult to ensure under the administrative separation of business lines required (or adopted in the case of some non-jurisdictional utilities) by Order 888. However, what is not known is whether any other generators would be willing to provide redispatch that would provide the same service, because there is no market for, or transparent pricing of, such a service currently.

Similarly there is no clear signal of the value of demand response at particular locations or times of the day or year. The lack of transparent hourly locational pricing severely limits the development of any demand-side response market that might be able to alleviate transmission constraints at peak demand hours or reduce requirements for peaking generation service to specific locations on the system.

In the absence of a large central transmission operator, the key issue is what, or who, enables the integration of information in order to facilitate informed decisions. Integration is important because transmission, differential generation location, including investment in distributed generation, and demand side measures are substitutes for one another in meeting end-use electrical demands. In each case, money can be spent in one area to save money in another area. Decisions in which the costs of one or the other of these substitutes are either ignored or distorted are likely to be wrong decisions and result in an inefficient electricity system.

Bonneville's transmission business line (TBL) has proposed a process for examining alternatives to transmission expansion projects and will be developing that process by looking at two example projects from its current expansion program. The process is analytical only, however, and does not include the ability to fund alternatives (though, of course, TBL does have, or expects to have, the ability to fund the transmission alternative). Bonneville's ability to expand its transmission system is contingent on continued Congressional approvals of borrowing authority.

Bonneville has, in the past, examined the possibility of incorporating locational and congestion-related information in its transmission rates, but only in a rudimentary and highly aggregated fashion (e.g., east side of Cascades vs. west side of Cascades). It did not pursue the possibility at the time and none of the other major transmission owners has proposed such rates. In Bonneville's case, the price differentials were not based on redispatch costs but, instead, were based on rough estimates of the construction cost differentials to bring generation to load from various parts of its transmission system.

Even if Bonneville were to attempt to incorporate better locational pricing information in its transmission rates (and it would have the best chance, since it is the largest transmission system in the Northwest), because it does not incorporate the entire Northwest system, the information would be limited to the effects on and the responses from the Bonneville system, both the transmission business line and the power business line, respectively. It would not be able to address the effects of parallel flow in any useful way outside of its system (see discussion of system operations above).

This problem has also been taken up by a westwide planning effort sponsored by SSG-WI and, just recently, by a northwest sub-regional planning effort hosted by the Northwest Power Pool's Transmission Planning Committee. (The latter is intended to be open to all participants, not just members of the Power Pool.) Both of these efforts aim to provide forward-looking examinations of the transmission system to look at economic congestion problems as well as reliability problems and to offer information about potential problems and solutions to those who might wish to sponsor projects in the future. They are not intended to provide mechanisms for implementing any particular project. These efforts will provide substantial useful information for potential transmission project sponsors, but the SSG-WI effort is not at this time intended to integrate that information with information about non-transmission alternatives to problems like expected congestion on the system. The Northwest sub-regional effort is intended to incorporate information about non-transmission alternatives to congestion problems, but the study plan has not been worked out so far.

In general, absent a larger central transmission operator, there is unlikely to be either a central institution that can replace the old vertically integrated utility framework or a pricing system that would offer the individual market participants the ability to get the same integrated information that would allow informed decisions. Individual utility least cost planning processes could get at the issue partially, but would have difficulty with the alternative ways of addressing the transmission system, since each utility only has a part of it. The current westwide and northwest sub-regional transmission planning efforts will, however, go a long way toward filling that information gap.

MARKET MONITORING

There is currently no active market monitoring entity in the West outside of the Market Monitor of the California ISO and the FERC Office of Market Oversight and Investigation (OMOI).

A regional transmission grid operator would maintain an independent market monitoring capability, as required by Order 2000. There are also discussions among the three western regional transmission grid operator candidates (RTO West, the California ISO, WestConnect in Arizona/New Mexico/Colorado) about formation of a west-wide market monitoring unit. If that happens, it would likely replace individual regional transmission grid operator entities.

The market monitor would have the authority to independently review, study and report on all markets created, administered, coordinated or facilitated by the regional transmission grid operator. The market monitor may report studies and findings, at its discretion, to FERC, the Department of Justice, state and provincial regulatory and enforcement authorities and the regional transmission grid operator's board of directors. The market monitor could also provide periodic reports on electricity markets to the board of directors, market participants and other interested parties.

The market monitor would not have the authority to enforce laws, impose penalties or implement price mitigation schemes or tariff changes. It could, however, recommend to the appropriate entities that any of these things be done, including recommending emergency actions to the regional transmission grid operator's board of directors (which would in turn require confirmation by FERC).

There is currently an active effort by the states to develop some sort of westwide market monitoring entity that would exist whether or not additional regional transmission grid operators are created in the West. Only initial steps have been taken so far. The question of access to the kind of data that would be required to evaluate problems in the transmission and energy markets will be a major one for this proposal to address. WECC EHV data pool data on real time dispatch and transmission conditions is a candidate for a data source but is not the same scope as the data that would be available to a regional transmission grid operator. Moreover, the data pool's availability to outside (non-control area) entities has been problematic in the past and that condition is likely to continue in the future unless NERC and WECC membership and standards are made mandatory through federal legislation (versions that deal with this problem are pending in the Congress at this time, but passage has failed several times in the past). The fact of the states working together with FERC's OMOI may help in the resolution of some of these issues.

APPENDIX B

TRANSMISSION-RELATED ACTIVITIES CURRENTLY UNDERWAY

There are a number of activities underway in the region to address current transmission issues. Some of these have been referenced in the discussion above. This section provides a little more detail on these activities

RTO West

RTO West is currently in the middle of a process for exploring with the Regional Representatives Group (RRG) what basic problems exist with the NW transmission system; what potential solutions exist and how they might be implemented, in an attempt to reach regional consensus on these questions. There are currently different views of the weighting of the existing RTO West proposal in these discussions; some believe that it should be accorded no weight while others believe that it represents a good starting point for a discussion of solutions.

One likely outcome of the RTO West RRG process may be to fold in the discussions of the Transmission Issues Group, which was originally set up as a forum to discuss alternatives to RTO West.

SSG-WI

The SSG-WI Planning Work Group provides a forum for an expansive westwide look at potential transmission needs over the next 10 years. It is intended to complement existing WECC reliability and path rating work. Historically, individual sponsors have proposed transmission projects and a project-specific WSCC/WECC review group has been created to examine the proposal and its effects on other existing paths, both to establish whether the project is the best one to meet the need and to rate the path. The SSG-WI process is intended to look at potential transmission needs and alternatives to transmission under several scenarios, as a means of providing information to potential project sponsors and policy makers, among others. It will focus on larger transmission paths that involve more than one sub-region (or RTO footprint) in the West while integrating sub-regional planning efforts.

NW Sub-Regional Planning process

An effort is underway to create an analogous sub-regional planning forum in the Northwest that would go beyond the traditional, project-specific review. This would be expected to integrate into the SSG-WI process as well as providing stand-alone information. A open-membership group, the Northwest Transmission Assessment Committee, has been formed under the auspices of the Northwest Power Pool's Transmission Planning Committee. The NTAC has had initial meetings focused on defining its charter and approach to the issues.

BPA TBL Transmission Alternatives project

The TBL has a project to examine non-transmission alternatives to specific projects in their G-9 list, as a pilot examination of the general question of trade-offs between transmission and non-transmission solutions to load service.

Utility Integrated Resource Plans

Some of the utility integrated resource plans contain provisions for transmission expansion and some focus only on generation and demand-side alternatives. There is no common practice in the ones that are currently being examined.