TRANSMISSION SYSTEM AND RTO ISSUES

Introduction

The Power Committee has been wrestling with some of the issues raised by the initiative to form a regional transmission organization, RTO West. Much of the focus has been on the benefit/cost analysis and some of the mind-numbing details of the proposal. The benefit/cost study is an important piece of information. Strong arguments have been made that the RTO West benefit/cost study significantly overstated the quantified benefits and was not able to establish a large monetary penalty due to existing inefficiencies in the dispatch of the system (this is also consistent with the earlier results of the IndeGO benefit/cost study done several years ago). The benefit/cost study should not, however, be the sole determinant of whether there are problems with the existing transmission system and whether an RTO is the appropriate approach for resolving those problems.

This paper is an attempt to step back from many of the details of the RTO West submittal and look at what problems exist or are likely to exist on the transmission system as it is currently structured, how these problems are addressed in the RTO West framework and how they might be addressed in a non-RTO framework.

Context

The context for the discussion is the current open access environment under Order 888. It is important to put the RTO West proposal in the context of the existing transmission system, and to understand the growing problems that the existing system faces today and into the future. These problems arise from the fundamental changes coming to the industry from the creation of, and reliance upon, a third-party merchant generation sector and, at least partially, from retail access. However, even if retail access proceeds no further or even if existing open access jurisdictions are re-regulated, Staff believes it is very unlikely that wholesale power market will turn away from independent generation in any significant way. Consequently, many of the transmission issues driven by the wholesale generation market are likely to remain.

The regional transmission system began as systems designed to connect the generation of individual vertically-integrated utilities with their load centers. As a consequence of the increasing reliance on merchant generation and the opening of the wholesale market generally, there has been a tremendous increase in both the number of transactions[1] going across the transmission system. In addition, changes in the spatial location of generation (sources) and the location of the loads they serve (sinks) are resulting in a pattern of transactions that is much different than that for which the transmission system was designed. It is these changes that are beginning to stress the system.

[1] For example, in the first quarter of 1995 power marketers traded 1.8 million megawatt-hours of electricity in the United States. By the first quarter of 1999, trade by power marketers had increased to over 400 million megawatt-hours. Source: U.S. Department of Energy, Energy Information Agency, *Wholesale Competition in the U.S. Electric Power Industry Fact Sheet*, June 13, 2001. http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/wholesale.html

To be clear, Staff does *not* believe that the management of the existing system currently faces overwhelming problems, especially in the West. We do not currently face the large-scale problems of inefficient transaction management and curtailments that are evident now and getting worse in the Eastern Interconnection. These Eastern problems contributed significantly to the price spikes that occurred in the Midwest several years ago.

At the same time, the existing transmission system management is showing strains that are intrinsic to the management approach itself. There are patches that will make it work better, but the discrepancy between a commercial system based on contract paths and the physical reality of actual power flows over a network will, Staff believes, increasingly cause problems. Moreover, the lack of transparent locational price information will not support informed investment decisions, especially in an institutional setting with fragmented decision making by individual market participants.

The RTO proposal represents a basic change in the way commercial transactions are dealt with and in the way they relate to the underlying physical system. It is *one* kind of response to the issues that are arising from the fundamental changes that are coming to the industry. There are, however, other possible responses.

The following paper and summary matrix are an attempt to describe the problems facing the system, describe how they would be addressed in an RTO and to describe how they might be addressed without the kind of fundamental changes represented by an RTO. While the RTO West proposal is usually cited in the description of an RTO approach, some other RTO configuration could well provide the same functions, without being identical to RTO West. Moreover, an RTO is not necessarily the only way to address these issues and other sections of the paper highlight other non-RTO mechanisms that could provide, or attempt to provide, similar functions. Other less comprehensive approaches could be taken, but the problems exist now and will not go away by themselves.

The major areas to be addressed are system operations, for both access and reliability, system expansion and market monitoring. Accountability with and without an RTO will also be described.

SYSTEM OPERATIONS, ACCESS AND RELIABILITY

Current Status and Issues

The central operating, access and reliability issues have to do with how generation is dispatched to meet loads. Power flows from each generator over the entire transmission network in inverse relationship to the impedance[2] of the individual lines on the system. Except for specific limited cases, power flow over the network is not controllable, and cannot be directed to one or another specific line.

[2] 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.

The power flows over individual lines have to be kept within specific limits for system operating reliability (formerly termed “security”). 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.

If there is an outage of any of these 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, such that it might lead to system collapse before remedial action can be taken. System collapse could come from overloaded lines or further generators tripping off due to automatic relay operation, voltage collapse leading to automatic generation tripping and so forth. Generation is dispatched in a pattern that will avoid these problems in the case of the first contingency encountered by the system. This is called a “security-constrained dispatch.”

Congestion occurs 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 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.

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 largely operating combined cycle plants and aiming to sell into multiple western markets. It is being dealt with through the emerging bilateral and spot markets in the West.

It does, however, make the transmission problem more complex. On the one hand, we have the existing commercial system for wholesale transactions that is largely based on the concept of contract paths. On the other, we have actual power flow patterns that differ from the contract paths and that are shifting much more frequently and unpredictably than in the past.

Unscheduled Flows (Loop Flow)

Most wholesale contracts are point to point, path-specific contracts which do not take direct account of the network characteristics of power flows. The power flows that are not on the contract path are call unscheduled flows (also called loop flows or parallel flows). Native load service, like an IOU’s service to its retail load, as well as most Bonneville service to its wholesale customers, is network service, which does not specify particular paths.

Current path 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 loop in the West, which are managed through the Unscheduled Flow Mitigation Plan (UFMP) of the WECC[3], are becoming increasingly difficult to manage under the current regime. The UFMP requires a series of steps, beginning with accommodation by the path owner through restriction on its own schedules, followed by operation of the 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 that is when operating problems due to loop flow become apparent.

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 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.

In addition, because loop flow is not identified during the day ahead scheduling process, but only shows up in real time, this management difficulty is also a potential problem 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, and the schedules are not determined by the actual flow patterns but by contractual and commercial choices. This problem on the major Western 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.

The rest of the parallel flow problems in the West and Northwest, those which are not managed under the UFMP, are also managed largely by curtailment (except in the California ISO), either through agreements laid down in contracts or pro rata when no other rules apply. Many of the same problems arise here, and will become more difficult as the market is more heavily populated by merchant generators rather than vertically integrated utilities.

Transmission Access

In addition, there are access problems because transmission capacity may go unused in the short term when there is no long term Available Transmission Capacity (ATC)

[3] Western Electricity Coordinating Council, formerly the WSCC.

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,* indicated that there were substantial gaps between the effective Operating Transfer Capability[4] 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[5] as available for sale. 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 participants did not pursue access after the initial posting of no ATC.

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 when calculating imbalances with other control areas. 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 to, up to a limit, "borrow" energy from its neighbors during expensive hours and repay it during cheap hours.

One result of this competitive advantage is that in some parts of the country 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, new entrants seek to gain the commercial advantages currently enjoyed only by control areas. There are currently no restrictions that prevent this from occurring.

Rate "Pancaking" and Economic Dispatch

Rate pancaking, the charging of multiple average volumetric transmission rates[6] 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 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.

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[4] OTC: a measure of path rating accounting for seasonal or other current operating constraints.
[5] Open Access Same-time Information System: an internet-based reservation and scheduling system required under Order 888.
[6] Rates that are charged on a per unit of energy basis despite the fact that transmission costs are primarily fixed costs of capacity.

Operating Reserves

Finally, operating reserve requirements for reliability are met through a reserve sharing agreement in the Northwest, which reduces the total amount of reserves required from what would be required if individual utilities had to meet reserve requirements individually. Reserve requirements are not, however allocated to regions of the Northwest to ensure their availability despite congestion on transmission paths.

The RTO Approach

Unscheduled Flows

The RTO would essentially eliminate unscheduled flow problems because it would 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 would align the commercial system with the physical system. With appropriate coordination between the three RTOs in the West (a goal of the RTOs), loop flow from transactions with sources and sinks in other RTOs would also be eliminated.

The RTO is proposing to accept all schedules that are willing to pay congestion clearing costs (essentially the costs of re-dispatching the system to eliminate congestion. This would be in addition to those that have financial rights allowing them to waive congestion cost. These rights would either be pre-existing rights or rights purchased from the RTO. This approach will, on the one hand, ensure that no usable capacity is left on the table and, on the other hand, ensure that the maximum flexibility is offered to potential users of the system, consistent with physical reliability limits and existing users' rights.

The corollary redispatch markets that are also part of the RTO congestion management process will enable the RTO to manage these schedules while giving it the best set of tools to maintain the reliability of the system. These markets will also produce the locational price signals that will indicate to generators when it is profitable to operate and to transmission planners where it might be best to upgrade the transmission system.

There are currently 16 control areas in the RTO West area (eleven representing the filing utilities, including BC Hydro). The filing utilities' control areas would be replaced by a single RTO West control area, which would, in conjunction with the flow-based scheduling regime during day ahead, be able to examine likely real time power flows well ahead of real time, enabling a clearer overview of system status and prevention of potential system reliability problems.

Access

The RTO would also eliminate the scheduling limits across paths that are imposed on transactions between control areas. Because the RTO 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.

Rate Pancaking

The RTO 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. RTO West intends to continue working with the other potential RTOs in the West to develop some sort of reciprocity agreement that would eliminate all short-term and hourly rate pancaking.

Operating Reserves

The RTO would allocate reserve requirements to local areas to account for transmission constraints.

Alternative Approaches without an RTO

Unscheduled Flows

Without an RTO, 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 will require new tools that indicate more clearly the actual flows from individual 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).

Some have suggested that the UFMP itself will eventually have to be renegotiated (if there are no RTOs 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 RTOs because the UFMP 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.

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 just put officially in place. It is still suffering from extensive implementation problems. The problems are 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.

Operating Reserves

The Northwest reserve sharing agreement will likely need to be modified to account for the location of required reserves to take account of congested transmission paths.

Rate Pancaking

Rate pancaking would continue, unless eliminated under FERC's pro forma tariff.

SYSTEM EXPANSION

Current Status and Issues

The original vertically-integrated utility approach 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. 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.

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 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). There is little in the way of forward-looking planning for generation interconnection requirements beyond the requests that are made to the transmission owner (though Bonneville has done overview studies of the collective requirements of all the generation interconnection requests currently in its queue).

There is, outside of the California ISO's control area, no explicit pricing of transmission congestion. Congestion is generally managed in the forward markets through the presence or absence of ATC (available transmission capacity, capacity beyond that which, theoretically, is needed for vertically integrated utilities to serve their native loads) 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 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. 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.

Just as there is now no single entity with the authority and incentive to plan and invest in the transmission upgrades necessary to serve tomorrow's loads and generation, there is no single entity with the responsibility for ensuring that sufficient generation resources exist to meet peak loads. Utilities routinely serve some firm load through short-term market purchases. If their non-utility suppliers fail to deliver, the utility must find alternative sources or curtail load. The suppliers are subject only to whatever liquidated damages were negotiated into their supply contracts. Some have suggested that some sort of available supply capacity requirement should be imposed on load serving entities, as a mechanism to ensure that supply and demand imbalances neither get severe enough to limit ability to meet loads nor even to allow generators to charge higher than normal competitive prices. Currently there is no mechanism to ensure that all parties in a relevant region follow that requirement. Near universal participation is necessary, because the concept carries its own incentives to be a free rider on the actions of others.

The RTO Approach

The current RTO West proposal provides for a forward-looking, inclusive, least-cost planning process aimed at developing and providing information about potential problems, including both adequacy (its primary focus) and congestion problems[7], and information about potential solutions, both wires and non-wires. It also provides for facilitating independent project implementation, if desired by project participants.

The RTO West planning and expansion proposal relies primarily on market participant action in response to incentives built into the congestion management scheme via explicit prices to redispatch around congested paths. The RTO West proposal backs up this primary reliance on market participant action with RTO action to cause system expansion and to allocate costs for four specific kinds of problems.

These specific problems addressed by RTO West are the following:

- When a Participating Transmission Owner (PTO) has failed to provide sufficient Congestion Management Assets (the transmission capacity and redispatch actions that allow RTO West to manage the PTO's unconverted contract obligations),
- When a PTO has not maintained the original transmission capacity of its system,
- When a PTO has not met the transmission adequacy standards by providing enough capacity to meet load. And

[7] The planning document defines adequacy as "the ability of RTO West Controlled Transmission Facilities to deliver required power without regard to the cost of the power being delivered or the congestion costs incurred." Congestion problems are the rest, where the problem is the expense of alternative supplies, rather than sheer physical constraint. "Chronic significant congestion" is called out as a separate category for potential RTO action.

- In specific demonstrated instances of market failure precluding cost-effective mitigation of chronic, significant, commercial congestion.

With the exception of the last point on chronic congestion, the frequency of these backstop actions can be expected to be minimal. The frequency of the congestion backstop will depend on the existence or perception of market failure. Over time it might be expected to decline, however, leaving the RTO with an extensive planning and analysis role supporting action by individual market participants. In this case, transparent market prices play the integrative role formerly played by the vertically integrated utility, acting on internal information.

The locational pricing mechanisms and transparent markets operated by the RTO (in addition to continued and new bilateral markets) as part of its congestion management process will provide both the information and the appropriate incentives for substitute actions such as locating generation closer to loads and investing in demand response programs or load buybacks. In RTO West, they are intended to be the primary incentive for market participants to take any of these three major kinds of actions.

There are, however, several avenues for market participants to ask RTO West for cost allocation decisions that would spread the costs even of market participant-sponsored projects to other market participants. These, together with the congestion backstop provisions, are likely to, at least partially, offset the incentives for market participants to take actions based on their own interests and to wait for the RTO to act and to allocate costs.

If it were decided that some sort of available capacity requirement or some other mechanism to ensure adequate capacity were necessary, an RTO would be in a position to implement it.

Alternative Approaches without an RTO

The key issue is what, or who, enables the integration of information in order to enable 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.

It appears unlikely that utilities will step forward and reassert their traditional role in resource planning and development except to the extent that the role of independent merchant generators disappears. Utilities in the Northwest and elsewhere experienced the risks, both economic and regulatory, associated with investment in large, capital intensive generating plants during the 1970s and 1980s and even with smaller, less capital-intensive units in the early 1990s. Given the returns available to state-regulated utilities, most appear to have preferred to avoid risk by contracting with suppliers for shorter terms and incremental amounts of power in a way that was possible only through awkward partnerships before wholesale deregulation. Whether the recent experience has fundamentally changed that preference remains to be seen.

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).

Absent an RTO, NERC and WECC are the only entities that might be in a position to implement an industry wide available capacity requirement on load serving entities widely enough to avoid the breakdown of the requirement due to free riders, though that role is not clear for them. Individual utilities or regulators, or even states, would not have sufficient scope, though their actions could certainly be effective in ensuring that the utilities in their jurisdiction have sufficient resources. NERC and WSCC have in the past focused on reserve requirements for maintaining transmission system reliability, which is a lesser standard than reserve requirements to ensure meeting load[8] or avoiding extreme price spikes in the spot market. An extension to these latter areas might raise problems about intruding into commercial areas (WECC is specifically precluded by its bylaws from introducing standards on commercial issues).

In general, absent an RTO, 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.

[8] Transmission system reliability can be maintained by cutting load if there is insufficient generation.

MARKET MONITORING

Current Status and Issues

The only current market monitoring and collection effort in the West is that of the California ISO's Market Monitoring unit, though FERC has just issued an order requiring more frequent filing, in electronic form, of IOU and independent generator wholesale sales data. FERC is also increasing the staff of its market monitoring division.

The RTO Approach

RTO West would maintain an independent market monitoring capability, as required by Order 2000. RTO West's proposed market monitoring unit (MMU) would have the ability to report directly to FERC on abuses of market power and poor market rules, including those of the RTO. There are also discussions among the three western RTO 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 replace the individual RTO entities.

The MMU will have the authority to independently review, study and report on all markets created, administered, coordinated or facilitated by RTO West. The MMU may report studies and findings, at its discretion, to FERC, the Department of Justice, state and provincial regulatory and enforcement authorities and the RTO West Board. The MMU will also provide periodic reports on RTO West markets to the Board, market participants and other interested parties.

The MMU will not have the authority to enforce laws, impose penalties or implement price mitigation schemes or tariff changes. It may, however, recommend to the appropriate entities that any of these things be done, including recommending emergency actions to the RTO West Board (which would in turn require confirmation by FERC).

Alternative Approaches without an RTO

It is unlikely that there would be extensive market monitoring capability developed outside of an RTO, (other that that at FERC) if for no other reason than that would be no other organization with the access to the kind of data that might be required to evaluate market problems in the transmission and energy markets. 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 an RTO MMU. 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).

ACCOUNTABILITY

Current Status

Reliability standards are set by NERC and WECC and are primarily directed at control area operators. Some of the pending national legislation would extend the reach of reliability standards to other market participants as well.

Currently both state regulated and federal utilities have some level of third party liability protection from lawsuits over the operation of their transmission systems in the event of outages. There is concern that this level of protection would be substantially weakened if an RTO were to operated the transmission assets and these utilities would be exposed to substantially more liability than they currently are.

Transmission is regulated by both FERC and states for IOUs (though the current jurisdictional lines may be shifting due to the recent Supreme Court ruling reaffirming FERC's jurisdiction over all IOU interstate transmission under the Federal Power Act and reaffirming that essentially all transmission is "interstate"). Currently, states set the rates for transmission service provided to native loads by IOUs. Bonneville's transmission is primarily under its own regulation, subject to some limited FERC authorities, and decisions are often driven in part by political pressures.

The RTO Approach

Reliability standards would continue to be set by NERC and WECC, though the RTO would have the obligation to bring to FERC's attention any reliability standards that impinge on the RTO's ability to provide non-discriminatory service.

RTO West has requested that FERC address the potential exposure to increased third-party liability for outages and other transmission problems that the RTO might face. FERC has not agreed to do this, but the filing utilities are pursuing the matter with FERC.

Jurisdiction over access, transmission rates and terms and conditions of service of the RTO would lodge at FERC, as would that over the transmission revenue requirement of the IOUs (though the revenue requirement of Bonneville would still be set in the current manner).

Alternative Approaches without an RTO

This would be largely the same as current status (which may be changing as FERC asserts more jurisdiction over IOU transmission than it currently uses, due to the Supreme Court decision noted above).

Category	Problem	RTO-W Solution	Non-RTO Solution
System Operations, Access and Reliability			
Economic Efficiency	Unscheduled (Loop) flow managed by curtailments in real time that ignore value relative value of transactions. Transactions that might be willing to be curtailed for a price are not curtailed and those that would be willing to pay the price are curtailed	Instead of schedules based on contractually defined paths, schedules are based on evaluating the physical power flows across entire network. All schedules with financial rights or willing to pay applicable congestion charges accepted -- higher value transactions accommodated.	Contract path approach and control area scheduling limits probably maintained. More market oriented solutions required to avoid uneconomic curtailments.
Reliability	Loop flow problems managed by real-time curtailments, the consequences of which may can threaten reliability. Entity expecting load service will have to scramble to find alternative supplies in near real-time. May not solve loop flow problem and may create additional problems.	RTO will implement scheduling based on actual power flows virtually eliminates need to manage loop flow in real time.(Big effort – heart of RTO).	New tools required to show actual flows resulting from schedules to permit control areas to cut schedules in a timely fashion. E-tagging will provide faster transfer of information across control area boundaries but won't eliminate loop flow.
Complexity/ Reliability	Already 16 control areas. System for reconciling imbalance charges creates incentive for merchant generators to form control areas. Increasing numbers of transactions further increases complexity. Complexity of scheduling potentially risks reliability.	Filing utilities 11 control areas combined into one – reducing complexity. Imbalance market removes incentive for generators to form control areas.	Potential change in settlement of imbalance charges will eliminate one incentive for new control areas but complexity of multiple control areas remains.
Reliability	Regional security (reliability) coordinator can see the entire system in real time but not ahead of time but must order actions to be taken by individual control areas.	Single control area operator can see entire system a day ahead as well as real time and take action directly to control reliability problems.	None proposed.

Category	Problem	RTO-W Solution	Non-RTO Solution
System efficiency	Pancaking of volume-based transmission charges across 2 or more systems adds cost to transactions and can prevent the most economic dispatch of the system.	Rate pancaking within the RTO is eliminated. At the boundaries of the RTO there is still pancaking unless there is a reciprocity agreement.	Rate pancaking will continue unless eliminated under FERC's pro forma tariff.
System Access/ Utilization:	Available short-term transmission capacity goes unused when there is no long-term ATC or scheduling limits between control areas doesn't reflect actual flow constraints. This thwarts possible transactions and can result in higher costs. Surveys over past several years show actual availability of transmission capacity when posted ATC was zero.	Not a problems since all schedules are accommodated that either have firm rights or are willing to pay applicable congestion charges.	Active marketing of ATC and active third party redispatch market might reduce problem.
Operating Reserve Require-ments	Reliability standards set by NERC and WECC directed at control area operators. Operating reserves met through reserve sharing, however reserves not allocated to local areas to ensure availability despite possible congestion.	RTO would allocate reserve requirements to local areas to account for transmission constraints.	Modify reserve sharing to account for transmission constraints.
Load/resource balance	Load serving entities may not carry sufficient capacity/energy to cover periods of extreme load growth or drought. There is an incentive to "free-ride" on others – hoping that others will carry sufficient supplies to cover them. Example: 2000-2001 regional utilities clearly did not have sufficient supplies.	RTO could be a vehicle for implementing capacity requirement that avoided the free-rider problem. Not part of current RTO proposal.	Individual systems can protect themselves if they carry sufficient capacity.

System Expansion:			
Category	**Problem**	**RTO-W Solution**	**Non-RTO Solution**
Lack of investment	Regulatory uncertainty disincentive to transmission investment -- uncertainty about future ownership/control of transmission.	Going forward with RTO will remove some level of uncertainty.	Transmission will be built for specific requests for service and costs most likely allocated to the requester. If FERC continues pressure for separation of generation and transmission, uncertainty remains.
Lack of investment	Generation planned and sited by independent generators. Lead time for siting/building generation less than that for many transmission solutions. Risk that generation will displace need for transmission.	Problem remains.	Problem remains.
Least cost solutions	No integrated planning of generation, transmission and load management.	RTO will carry out a comprehensive, forward looking least cost planning approach to identify problems and solutions, both wires and non-wires. Primary reliance on market solutions (responding to congestion costs) but RTO backup in specific cases.	Bonneville TBL trying to implement a comprehensive evaluation wires and non-wires solutions, However, TBL does not propose to fund alternatives to wires.
Information for decision-making	No explicit congestion pricing means no economic signals regarding the location of generation or the relative effectiveness of demand side solutions.	Transparent location pricing based on redispatch costs would provide economic signal for alternative solutions.	Bonneville has proposed crude form of locational pricing. However, it could not be comprehensive if only Bonneville did it.
Most efficient transmission solutions	Least cost solution may exist on another transmission owner's system. Puget Sound area – Bonneville forced to pursue solutions on their system that could be implemented cheaper on others' systems.	RTO would probably have ability to cause implementation of least cost solutions within RTO if the situation fits the criteria for one of the backups.	One would think money would solve the problem but it hasn't yet.

Market Monitoring			
Category	**Problem**	**RTO-W Solution**	**Non-RTO Solution**
Market Power	No single independent entity outside of FERC has the access to the information to identify instances market power abuse. FERC has limited jurisdiction (IOUs only).	Independent market monitoring unit with access to information and ability to report appropriate authorities, e.g. FERC, DOJ. More comprehensive than FERC.	FERC has just issued order to require reporting of quarterly data by jurisdictional utilities and is increasing size of market monitoring staff.
Accountability			
		Independent board with stakeholder advisory groups that include customers and state regulators. RTO Board is under the authority of FERC.	State and Local regulators and local political influence on Bonneville. FERC regulation of interstate transmission of IOUs, limited regulation of Bonneville transmission.

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