CHAPTER 2: MONTANA ELECTRIC TRANSMISSION GRID: OPERATION, CONGESTION AND ISSUES

The transmission grid serves the vital function of moving power from many different generating plants to customers and their electric loads. However, it does more than that: it provides service robustly and reliably even though individual elements of the transmission grid may be knocked out of service or taken out of service for maintenance. This paper describes how the transmission grid developed; how it works in terms of physics and how it is managed commercially; and how reliability is ensured. It discusses the ownership and rights to use the system; the extent of congestion and how it is managed; and how management would be changed under the proposed RTO West. Finally, it discusses several issues involved in the construction of new transmission lines to expand the capacity of the grid.

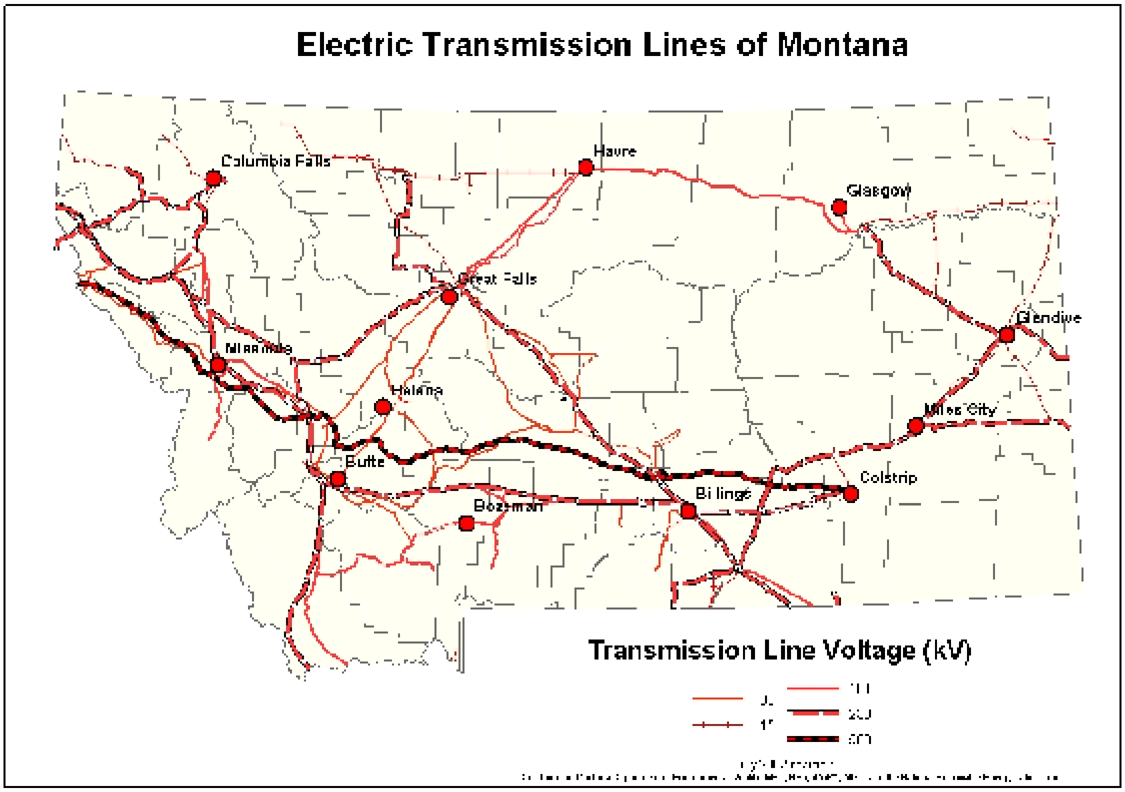
1. Historical Development of Transmission in Montana

The transmission network in Montana, as in most places, developed over time as a result of local decisions in response to growing demand for power and decisions on where to build generation. The earliest power plants in Montana were small hydro generators and coal-fired steam plants, built at the end of the nineteenth century to serve local needs for lighting, power and streetcars. The earliest long distance transmission lines were built from the Madison plant, near Ennis, to Butte and from Great Falls to Anaconda. The latter was at the time of construction the longest high voltage (100 kilovolt—kV) transmission line in the country.

As the Montana Power Company (MPC—now NorthWestern Energy) system, and coop loads dependent on MPC's system for delivery grew, MPC expanded its network to include 161 kV and ultimately a 230 kV backbone. Long distance interconnections did not develop until World War II. During the war the 161 kV Grace line was built from Anaconda south to Idaho. Later, BPA extended its high voltage system into the Flathead Valley to interconnect with Hungry Horse Dam and to serve the aluminum plant at Columbia Falls.

Montana's strongest interconnections with other regions are now the 500 kV lines from Colstrip to Spokane, the BPA 230 kV lines heading west from Hot Springs, PacifiCorp's interconnection from Yellowtail Dam south to Wyoming, WAPA's DC tie to the east at Miles City, and the AMPS line running south from Anaconda parallel to the Grace line to Idaho.

Figure ET1. The Montana transmission network

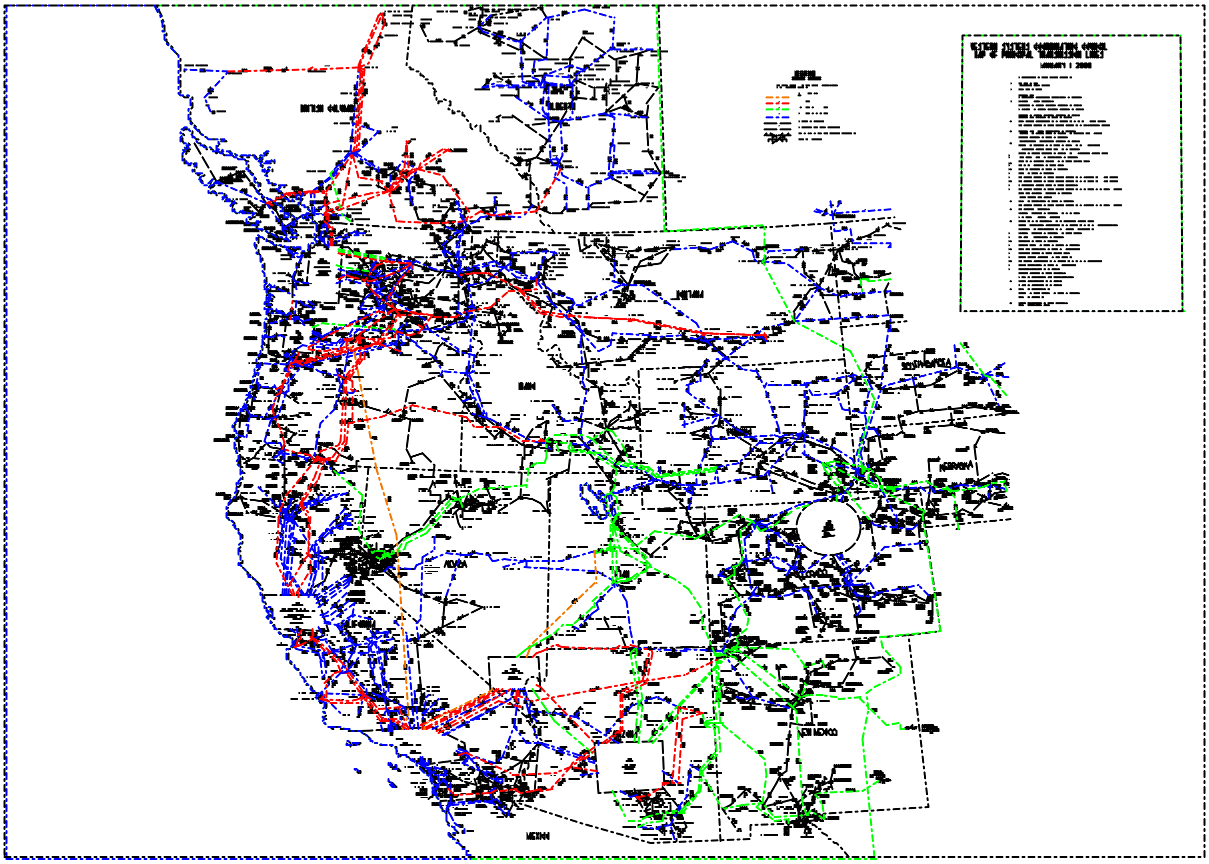


As U.S. and Canadian utilities have grown and increasingly depended on each other for support and reliability, the North American transmission network has developed into two major interconnected grids, divided roughly along a line that runs through eastern Montana south to west Texas. The western United States is a single, interconnected and synchronous electric system (see next page). Most of the eastern United States is a single, interconnected and synchronous electric system. Texas and Quebec are exceptions; Texas is considered a separate interconnection with its own reliability council, ERCOT.

The interconnections are not synchronous with each other. Each interconnection is internally in synch at 60 cycles per second, but each system is out of synch with the other systems. They cannot be directly connected because there would be massive instantaneous flows across any such connection. Therefore they are only weakly tied to each other with AC/DC/AC converter stations. One such station is located at Miles City. It is capable of transferring up to 200 MW in either direction. Depending on transmission constraints, a limited amount of additional power can be moved from one grid to the other by shifting units at Fort Peck Dam. By contrast, this transfer capacity is about one tenth the peak load in Montana, which is one of the smaller loads in the West.

There are currently three DC converter stations between the western and eastern grids with a combined capacity of 510 MW. Three more are planned or under construction at Lamar, in eastern Colorado, Rapid City, and Miles City. There are also two converter stations with a combined capacity of 420 MW linking the Western Interconnection with ERCOT. The peak load of the Western Interconnection, by comparison, was around 131,000 MW in 2000.

Figure ET2. The Western Interconnection transmission network



Most of Montana is integrally tied into the Western electrical grid. However the easternmost part of the state, with around 5 percent of total Montana load, is part of the Eastern Interconnection and receives its power from generators in that grid.

2. How The Transmission System Works

There are big differences between the way the transmission system operates and is managed physically, and the way it is operated commercially. The flows of power on the transmission network follow certain physical laws. Transactions to ship power across the grid follow a different and not fully compatible set of rules.

<u>Physical operation:</u> The transmission grid is sometimes described as an interstate highway system for electricity, but the flow of power on a grid differs in very significant ways from the flow of most other physical commodities. First, when power is sent from one point to a distant

location on the transmission grid, the power will flow over all connected paths on the network. It will distribute itself so that the greatest portions flow over the paths of lowest resistance ("impedance," in alternating current circuits), and it generally cannot be constrained to any particular path or contract path. For example, power sent from Colstrip to Los Angeles will flow mostly west to Oregon and Washington and then south to California. But portions will flow south via Garrison into Idaho, and even southeast from Colstrip into Wyoming and then south to Arizona before continuing to Los Angeles.

A second way in which power flows differently than other commodities is that flows in opposite directions net against each other. If traffic is congested in both directions on an interstate highway it will come to a halt in all lanes and not a single additional vehicle will be able to enter the flow. By contrast, if 100 MW were shipped westbound on a transmission line from point A to point B, and 25 MW were sent simultaneously eastbound from point B to point A, the actual measured flow on the line would be 75 MW in a westbound direction. If 100 MW were sent in each direction the net measured flow would be zero. If power were shipped simultaneously in opposite directions at the full capacity of a transmission line, the net flow would be zero, and additional power still could flow in either direction up to the full capacity of the line.

As a consequence of the above factors, the actual flows on the network are the net result of all generators and all loads on the network. In any real transmission network there are many generators located at hundreds of different points on the network, and many loads of varying sizes located at thousands of different locations. Because of netting, regardless of where power is sent or from where it is purchased, path loadings will depend only on the amounts and locations of electric generation and load.

<u>Management of the grid</u>. In contrast with the physical reality of the transmission network, management of transmission flows has historically been by use of a "contract path": A transaction shipping power between two points will be allowed if space has been purchased on any path connecting the two points, from the utilities owning the wires (or the rights to use those wires, if they are transferable) along that path. Transactions are deemed to flow on the contract path. Portions that flow on other paths are termed "inadvertent flows" or "unscheduled flows."

For example, power sent from Colstrip to the West Coast uses a contract path along the 500 kV lines through Garrison and Taft, then across the West of Hatwai path into western Washington and Oregon. However somewhere between 15 and 20 percent of the power actually flows south across two other paths, the Yellowtail-South path and the Montana-Idaho path south from Anaconda.

The topology of the western grid is such that major inadvertent flows occur around the entire interconnection. Power sent from the Northwest to California flows in part clockwise through Utah and Colorado into New Mexico and Arizona and then west to California. Conversely, a portion of power sent from Arizona to California flows counterclockwise through Utah, Montana and Idaho, then west to Washington and Oregon, and then south into California. These major inadvertent flows are called "loop flow." Expensive devices ("phase shifters") have been installed at several locations to control loop flow and to limit its effect on owners of affected portions of the grid.

Owners of rights or contracts on contract paths are allowed to schedule transactions as long as the total schedules do not exceed the path ratings. Scheduling against reverse flows is not allowed, despite their netting properties, because the capacity created by reverse schedules is not deemed to be firm. (If the flow scheduled in one direction was reduced at the last minute, capacity to carry power in the opposite direction would automatically go down by the same amount.)

Inadvertent flows may interfere with the ability of path owners to make full use of their rights. The Western Electricity Coordinating Council (WECC) Unscheduled Flow Reduction Procedure requires utilities whose wires are affected by inadvertent flows to first accept flows up to the greater of 50 MW or 5 percent of the path rating by curtailing their own schedules. If further reductions are necessary the path owners can request the operation of phase shifters (to block loop flows) or curtailments of schedules across other paths that affect their ability to use their own path. Phase shifters are limited to operation no more than 2000 hours per year, because they have limited lifetimes and are degraded by use.

The shift to management of the grid by an RTO (discussed below) will do away with the use of the contract path, and with it, the necessity for special management of inadvertent flows.

If the scheduled flows do not exhaust the path rating, the unused capacity may be released as non-firm transmission capacity. This capacity cannot be purchased in advance; it can be scheduled only at the last hour. Owners of capacity who do not plan to use it could release it earlier, but often are reluctant to do so because of their own needs for flexibility or a desire to withhold access by competitors to their markets.

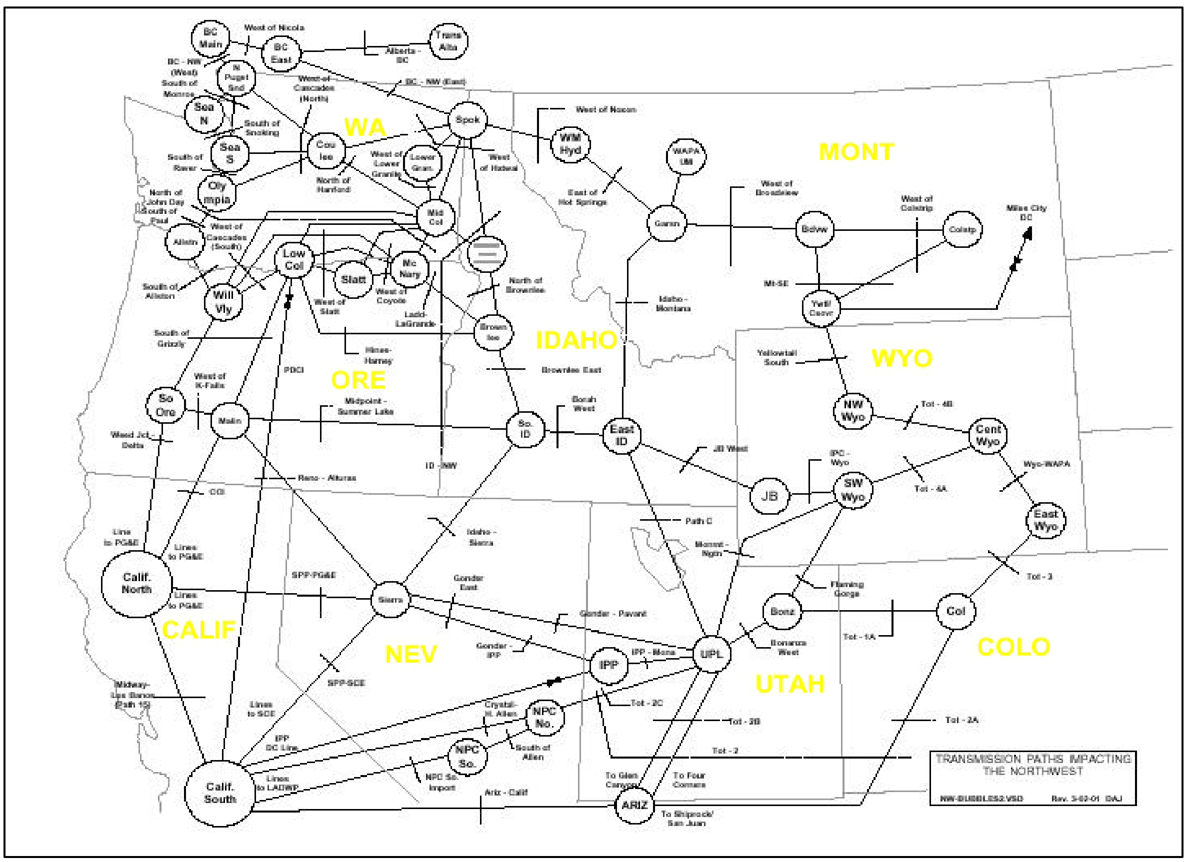
3. Grid Capacity and Reliability

The amount of power a transmission line can carry is limited by several factors. A major factor is its thermal limit. When flows get high enough the wire heats up and stretches, eventually sagging too close to the ground and arcing. Other factors relate to inductive and capacitative characteristics of AC networks. (Inductive characteristics are associated with magnetic fields that are constantly expanding and contracting in AC circuits wherever there are coils of wire such as transformers. Capacitative characteristics are associated with electric flows induced in wires that are parallel to each other, such as long transmission lines.) But the most important factor, indeed the limiting factor, is reliability. The transmission network is composed of thousands of elements that are subject to random failure, caused by such things as lightning strikes, ice burdens, pole collapse, trees falling on conductors and vandalism. Since customers value reliability and can be greatly harmed by loss of power, reliability of the grid is assured by building redundancy into it. The grid is designed to withstand the loss of key elements and still provide uninterrupted service to customers. Service is provided by the network, not by individual transmission lines. Reliability concerns limit the amount of power that can be carried to the amount of load that can be served with key elements out of service.

Two examples will show how this applies. Within Montana Power's service area the reliability of the transmission system is evaluated by computer simulation of the network at future load and generation levels, taking individual elements out of service and determining whether all loads can be served with voltage levels and frequencies within acceptable ranges. If acceptable limits are violated, the network must be expanded and strengthened. Typically this means adding transmission lines or rebuilding existing ones to higher capacities. Identical procedures are used by other utilities and by regional transmission and reliability organizations.

The second example relates to major transmission paths used to serve distant load or to make wholesale transactions. Paths are bundles of related transmission lines that carry power between the same general areas. Most major paths are rated in terms of the amount of power they can carry, based on their strongest element being unavailable. (In some cases the reliability criteria require the ability to withstand two or more elements out of service.) For example, the Colstrip 500 kV lines are a double circuit line, but they cannot reliably carry power up to their thermal limit because one circuit may be out of service. Recently there has been a move by the Western Electricity Coordinating Council, which is the reliability council for the Western Interconnection, to require the paths of which the Colstrip lines are a part to model both circuits out of service, because of the possibility of a tower collapse.

Figure ET3. Rated paths on the transmission network



The paths through Montana toward the west have been rated and are limited generally to 2200 MW east to west. The West of Hatwai path, which is comprised of a number of related lines west of the Spokane area, is rated at 2800 MW.

4. Ownership and Rights To Use The Transmission System

Rights to use the transmission system are generally held by the owners or by holders of long-term contract rights. Rights to use rated paths have been allocated among the owners of the transmission lines that comprise the paths. In addition the owners have committed to a variety of contractual arrangements to ship power for other parties. Scheduled power flows are not allowed to exceed the path ratings.

FERC Order 888, issued in April 1996, required that transmission owners functionally separate their transmission operations to make them independent of their power marketing operations. They must allow other parties to use their systems under the same terms and conditions as their own marketing arms. They must maintain a web site ("Open Access Same Time Information System," or OASIS) on which available capacity is posted.

Available transmission capacity (ATC) is calculated by subtracting committed uses and existing contracts from total rated transfer capacity. Little or no ATC is available on most major rated paths, including those leading west from Montana to the West Coast. The rights to use the capacity are fully allocated and closely held. None is available for purchase by new market entrants.

These existing rights – and ATC, if any were available – are rights to transfer power on a firm basis every hour of the year. The owners of the rights on rated paths may or may not actually schedule power in every hour, and when they don't, the space they are not using may be available on a non-firm basis. In fact, the paths are fully scheduled for only a small portion of the year, and non-firm space is almost always available. For example, according to MPC, in the 12 months through September 2001, the West of Hatwai path was fully scheduled or over-scheduled about 8 percent of the time. The remainder of the time, 92 percent of the year, non-firm access was available.

However, non-firm access cannot be scheduled in advance or guaranteed. It is a workable way to market excess power for existing generators. It may be a reasonable way to make firm power transactions if backup arrangements can be made to cover the contracts in the event the non-firm space turns out to be unavailable. However it may be difficult to finance new generation if it cannot be shown with certainty that the power can be moved to market.

5. Congestion

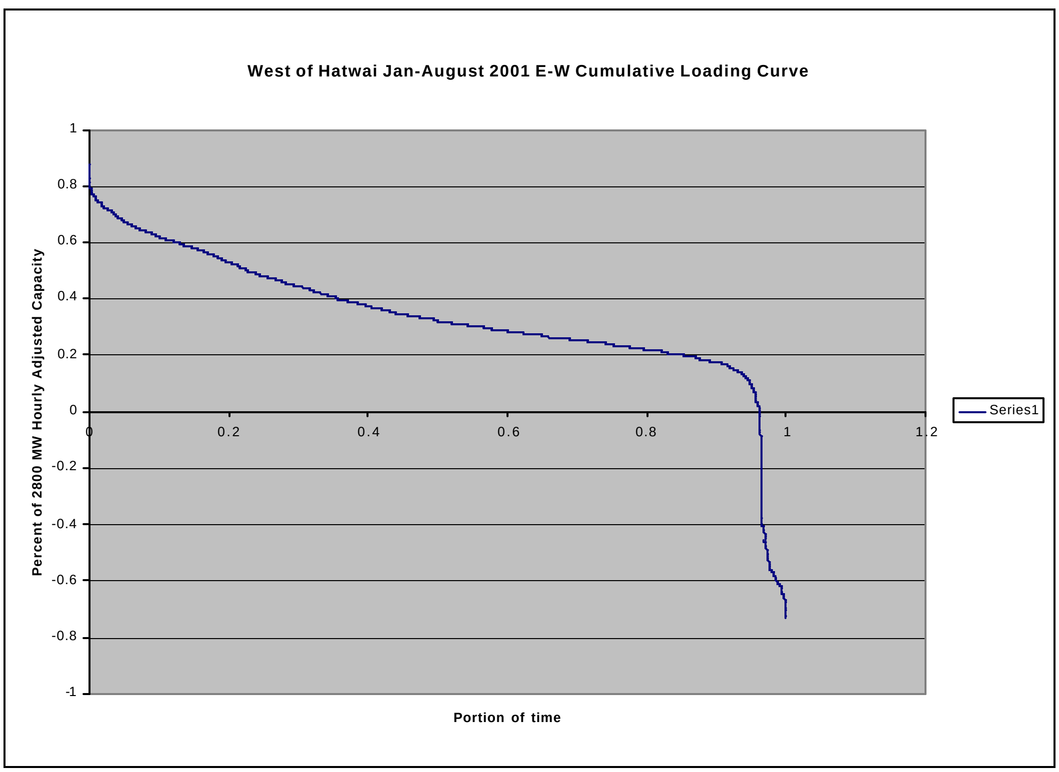
A transmission path may be described as congested if no rights to use it are for sale. Alternately, congestion could mean that it is fully scheduled and no firm space is available. Or it could mean that the path is fully loaded. These are three different concepts.

By the first definition, the paths west of Montana are congested – no rights are available and no ATC is offered for sale on the OASIS.

By the second definition, the paths are congested a few hours of the year - the rights holders fully use their scheduling rights a fraction of the time, and the rest of the time they use only portions of their rights. From October 2000 through September 2001, the West of Hatwai path was congested under this definition around 8 percent of the time.

The third definition is based on actual loadings. Actual loadings are different than scheduled flows because of the difference between the physics and the management of the grid – schedules are contract-path-based, and actual loadings are net-flow-based. Actual flows on the paths west of Montana are almost always below scheduled flows, because of the net impacts of inadvertent flows and loop flows. Actual hourly loadings on the West of Hatwai path are posted on BPA's OASIS site. Figure 4, below, shows that the first eight months of 2001, highest actual loadings were around 90 percent of the path capacity for only a few hours. For most hours the path was not heavily loaded. By the third definition, the lines currently are never congested – even when the lines are fully scheduled, the net flows are below path ratings.

Figure ET4. West of Hatwai path cumulative loading curve Jan-Aug 2001
(Negative flows mean power was flowing from west to east)



6. Grid Management By RTO West

Discussions have been underway for several years among the transmission owners and other stakeholders in the Northwest to have an independent body take over operation and control of access for the transmission system. This was partly out of a recognition by the transmission owners that proof of independence, as required by FERC Order 888, would become an increasingly difficult burden, and partly out of anticipation that FERC would ultimately move to order such a transfer. Initial discussion revolved around IndeGO, a proposed independent system operator that would lease and operate the wires. The IndeGO discussions ultimately foundered on cost-shifting concerns, but after FERC issued Order 2000 the discussions revived, focusing now on a Regional Transmission Organization (RTO) that would operate the system under a contractual Transmission Operating Agreement (TOA) with the participating transmission owning utilities.

Assumption of responsibility for grid management by RTO West is important because for the first time it would provide for a market-driven means of managing congestion. The current fixed assignment of rights to use the grid prevents non-incumbents from making use of unused capacity, and even hinders their ability to bid for it. The RTO would allow all parties to signal their willingness to pay for access and to make efficient use of the grid. In addition the RTO management would result in congestion price signals that would allow economic decisions on location of new generation and on expansion of capacity on congested transmission paths. RTO West made its filing with FERC on March 29, 2002. Details of the filing can be found at http://www.rtowest.org/Stage2FERCFiling.htm.

7. Major Issues of Transmission

There are a number of issues affecting the transmission system and the need for and ability to complete new transmission projects. These include the downgrading of capacity for reliability reasons; the way reliability criteria are set; the limited number of hours the system is congested; the problems involved in siting high voltage transmission lines; the cost of new capacity; making the commitment for new capacity; and the alternatives for financing new transmission discussed in the Western Governors Association Transmission Study.

<u>Availability of Existing Capacity.</u> A considerable amount of existing capacity is not available for use because it is held off the table for reliability reasons when paths are rated. (See discussion of reliability issues, below.) Transmission owners may withhold capacity because of uncertainty, the need for flexibility and in some cases, a desire to protect their markets.

Uncertainty affects the transmission needs of utilities because they don’t know in advance what hourly loads will be or which generating units may be unavailable.

The need for flexibility affects transmission needs because utilities want the right to purchase power to serve their loads from the cheapest source at any given time. When RTO West tried to convert existing contract rights into flow based rights the claims greatly exceeded available capacity. This was largely due to utilities that had a right, for example, to move 100 MW on any of several paths, claiming a simultaneous right of 100 MW on all of them.

Withholding of capacity for market protection is a violation of Order 888. Withholding has been a problem since the order was issued, with a number of utilities around the country being cited and fined by FERC for violations. The failure of Order 888 to result in open and comparable access was a major reason for FERC Order 2000, which requires utilities to form RTOs.

Reliability Criteria. Reliability is an issue because the criteria governing the setting of path capacity and the operation and expansion of the transmission system relate only vaguely to economics. They do not reflect very well the probability or the consequences of the events being protected against. Since the system is quite reliable as currently built and operated, reliability concerns generally focus on very low probability events that may, depending on when they occur, have high costs. The criteria apply everywhere on the transmission grid despite the fact that in some areas and on some paths the consequences may be minimal while in other areas and other paths the same type of event may have large consequences. For example, Path 15 in central California or the Jim Bridger West path in Idaho, where a line outage can result in cascading failure and impact many millions of people, should probably be operated more stringently than parts of the transmission grid where an outage might cause a generating unit to trip off, but not affect any load.

Reliability criteria for the Western Interconnection are set by the Western Electricity Coordinating Council (WECC), which is part of the National Electric Reliability Council (NERC). The Western Electricity Coordinating Council was recently formed from a merger of the Western Systems Coordinating Council (WSCC) with several other transmission organizations.

WSCC was largely a creature of the transmission owning utilities. It historically was unsympathetic to applying cost-benefit considerations to the reliability criteria, although it recently convened a group to develop probablistic criteria that will likely be sensitive to economic concerns.

WSCC, at times, may have tightened reliability standards to increase reliability without regard to the impacts of its decisions. For example in 2001, WSCC set a 1000 foot separation rule for new transmission lines, precluding the use of existing corridors and rights of way for siting new lines adjacent to existing ones. In areas where siting opportunities are limited such a move may greatly increase the difficulty of building additional capacity.

WECC will have much broader representation on its board than the WSCC did, and will have stakeholder advisory committees.

Limited Hours of Congestion. As discussed above, the congested portions of the transmission grid tend to be fully or heavily scheduled and loaded only a few hours to a few hundred hours of the year. The rest of the time excess capacity is available, although it is a challenge to make use of it on a firm basis. Expanding capacity is expensive and difficult. Yet it has been the preferred method of gaining access for additional transactions and additional flows. If the costs could be assigned to the congested hours only it is very likely cheaper alternatives to new construction would be found. For example, some current users with relatively low valued transactions or with ready alternatives might be willing, at some price, to sell their rights to new users.

Siting. High voltage transmission lines can be difficult and contentious to site, especially in forested, mountainous or populous areas. For example, the Colstrip double circuit 500 kV lines were relatively easy to site in eastern Montana where they traversed rolling agricultural and grazing land. Siting in western Montana was a different story, particularly in the areas of Boulder, Rock Creek and Missoula. The resulting route had to stay away from the interstate highway corridor, instead opening new corridors through forested areas with issues such as impacts to elk security areas and increased access. Lengthy detours around Boulder and Missoula added considerably to the cost of the line. Rural growth and residential construction in western Montana since the Colstrip lines were sited in the early 1980s, combined with the already limited siting opportunities due to wilderness areas and Glacier National Park, can be expected to make siting challenges likely for additional construction.

Further, the recent proposed changes in WECC criteria, mentioned above, have increased the likelihood that new lines would have to open additional corridors instead of making use of existing corridors.

Cost. High voltage transmission lines are expensive to build. A typical single-circuit 500 kV line may run over $1 million per mile. A double-circuit 500 kV line may cost around $1.5 to $1.75 million per mile. 500 kV substations cost around $50 million each, depending on the complexity caused by their location on the network. If series compensation is required, 500 kV substations may cost up to $100 million. 230 kV lines are somewhat cheaper – about half the cost per mile of 500 kV lines, and substation costs run around $25-30 million each. DC lines are a bit cheaper but the equipment required to convert alternating current to direct current and back is extremely expensive, so this technology is generally used only for very long distance transmission with no intermediate interconnections. At present there are only two DC lines in the Western Interconnection – the Pacific DC Intertie, from Celilo in southern Oregon to Sylmar near Los Angeles, and the IPP line from the Intermountain Power Project generating station in Utah to the Adelanto substation, also near Los Angeles. Neither line has any intermediate connections.

Capacity for New Generation in Montana. There is considerable interest in Montana in building in-state energy facilities as an economic development tool. The lack of available transmission capacity to reach west coast markets may be a significant barrier. As discussed above, there is a considerable amount of unused capacity on the existing transmission network for a large part of the time, but it is not available on a firm basis. Changes in the way the transmission system is managed could make this space available, and could support some modest increase in new generation in the state. Significant additional generation would require new transmission capacity.

There is a “chicken and egg” problem in developing new transmission to facilitate economic development. If no capacity is available to reach markets, generation developers may have a difficult time financing their projects. Yet without financing, they probably can’t make the firm commitments for transmission services that would encourage utilities to invest on their own in transmission capacity for new projects. The alternative approaches, where the generation developers build needed new capacity or where new merchant transmission capacity is built in the hopes new generation will appear, still need to convince the financial markets that the transmission project is viable. In any event, the regulatory structure requires a showing of need for new transmission projects that may be difficult to make without firm commitments from generators. Of course, the regulatory requirements can be changed to accommodate economic development as a basis of need. Eminent domain is another matter. Eminent domain seizures could be at risk of court challenges if a landowner were to convince the court the public purposes of the line were speculative.

The issues confronting merchant plants are different than those faced under traditional utility procedures, where generation and transmission were planned, financed and built together. Generation developers either must absorb the risk of building new transmission capacity or convince some other party to absorb the risk for them.

<u>Western Governors Association Transmission Study.</u> In the spring of 2001 the WGA asked the utility industry and the Committee for Regional Electric Power Cooperation (CREPC—an organization of western states' public service commissions and energy offices) to study the need for new transmission in the Western United States. A working group of experts modeled the transmission grid and the likely growth of demand and new generation, and concluded that little new transmission (somewhere less than $2 billion over a 10 year period) would be needed beyond that already planned or under construction. This was a result of mostly natural-gas-fired new generation planned for locations close to loads or well served by existing transmission capacity. At the request of the Governors the group also studied a "fuel diversity" scenario in which half of new capacity was coal-fired generation or wind generation. This scenario resulted in a need for approximately $12 billion in new transmission capacity, including construction in Montana of a new 500 kV line to the West Coast and a new 500 kV line to Alberta.

The Western Governors Association then requested a study of how to finance new transmission lines, and the resulting report discussed two alternative proposals. The first was an "interstate highway" model in which all electric customers in the west would share in the costs of all transmission in the west, regardless of use. This model envisioned transmission expansion to eliminate most or all congestion. The second is a model in which the beneficiary pays: regional financing of reliability improvements, utility financing of load service improvements, and generation and customer financing of capacity expansions to eliminate congestion.

Each approach has advantages and disadvantages. The interstate highway model would avoid the need to determine the relative merits of different possible lines and simply eliminate all congestion. It would make a great deal more capacity available and could encourage the development of resources in places previously difficult to build. For Montana, it would make it easier to develop coal and wind resources. On the other hand, it would require agreement by all states and all utilities to spread the costs to all ratepayers. There is no existing agency with the authority to require such spreading and there is unlikely to be universal agreement to spread these costs without such an agency. The interstate highway approach could also result in overbuilding the transmission system, for example to alleviate congestion that may be minimal or that could be more cheaply addressed in other ways.

The “beneficiary pays” model is currently implementable and reflects the way transmission is currently financed for certain types of lines, such as lines needed for reliability and lines needed to serve growing utility loads. It results in a closer correspondence of benefits and costs than the interstate highway approach, and could make siting easier by reducing controversies over need. On the other hand, if future benefits are uncertain it could make financing difficult, and it would not provide the benefits to Montana coal and wind developers unless they were willing to pay the costs of needed transmission. Further, proponents of the interstate highway model are skeptical that the beneficiary pays model will result in the timely construction of new transmission capacity.