Northwest Power Supply Adequacy/Reliability Study Phase 1 Report

Northwest Power Planning Council

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Summary

Background

Approximately a year ago, Bonneville Power Administration Administrator Judi Johansen met with the Council to share her concerns about the evolving power supply situation in the Northwest. She cited Bonneville's annual White Book analysis, which showed that in the 2000-2001 operating year, 80 percent of the Septembers (out of the historical record of 50 water years) show deficits.[1] The average energy deficit in those years is equal to almost 2,500 average megawatts. Similarly, 36 percent of the Februarys show energy deficits that average 3,800 average megawatts. Problems in meeting the 50-hour sustained peak were also identified. Most of the supply-demand imbalance occurs on non-federal systems. Ms. Johansen noted the relative lack of new power plant construction taking place in the Northwest and questioned whether the competitive generation market would result in sufficient new development in the near term to avoid power supply problems. She encouraged the Council to undertake a review of the issue.

Objectives of the Council Analysis

Bonneville's White Book analysis is very valuable in terms of signaling the need for concern. However, there are several assumptions that could result in the White Book analysis painting an overly bleak picture. First, the analysis does not account for imports beyond existing firm contracts. In reality, the Northwest is part of a Western system with a good deal of seasonal diversity in loads that makes a certain degree of reliance on imports a cost-effective choice. Second, the White Book analysis does not reflect how the hydroelectric system can frequently (but not always) be operated to manage through relatively short-term supply problems. Finally, the White Book chooses not to speculate about possible new resource development. This is probably a prudent decision but it does seem likely that the operation of the power market will induce some level of new resource development.

In light of these limitations, the first phase of the Council's analysis attempts to answer the following questions:

- Is there a power supply adequacy problem for the Northwest over the next few years (5) taking into account flexible hydro operations; availability of imports; and known new resource development?

- If so, what is the nature of the problem in terms of its character (energy, capacity), magnitudes and probabilities? It is necessary to describe the situation in probabilistic terms taking into account hydro and temperature-induced load variability and forced generation outages.

- What are the interactions between operating the hydro system for reliability and meeting critical fish and wildlife targets for flows, reservoir levels, etc?

- What level of new resource additions is required to achieve typical industry reliability standards?

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[1] **1998 Pacific Northwest Loads and Resources Study (White Book),** Bonneville Power Administration, September, 1998. http://www.bpa.gov/power/pgp/whitebook/1998/index.shtml

- Is it likely the restructured/restructuring electricity industry will develop or maintain sufficient power supplies to address residual adequacy problems?

- If not, what are the options for addressing these problems?

The second phase of the study is intended to further refine key areas of the Phase 1 analysis and to evaluate the options for addressing adequacy problems.

Key Findings

There is a problem

Over each of the next few winters (the months of December, January, and February), with no new resources added to the system beyond those already under construction, there is a relatively high probability of one or more "generation insufficiency events" in which generation supply is not adequate to meet loads. Such events can be relatively small – tens of megawatts for an hour or a few hours. Or, such events can be quite large – several thousand megawatts for a few days. Both types of events are possible. The probability of a generation shortfall reaches approximately 24 percent by 2003. This means an almost one in four chance of one not getting through the winter without a supply interruption. These events are typically the result of some combination of poor hydro conditions, higher than normal demand due to weather conditions, and unplanned generation outages.

The kinds of problems experienced may be due to either capacity or energy shortfalls. Capacity problems occur when there is insufficient generating machine capability on the system to meet electrical demand during the peak hours of any given day.[2] Energy problems occur when, even if there is sufficient machine capability to meet peak hour demand, the capability of the system to deliver energy over a period of one or more days is less than the average demand over that time period. Capacity problems are typically associated with systems whose predominant generation is thermal, while energy problems are typically associated with principally hydroelectric systems. Historically, energy reliability has been the primary concern in the Northwest, but in the last few years concerns have been expressed about capacity, and this analysis indicates that the Northwest power system is transitioning to a state where a mix of potential capacity and energy problems exists.

The Council believes that a 24-percent probability of supply inadequacy is unacceptably large. There are a number of different reliability measures used in the electricity industry, but the 24 percent falls into a category called Loss of Load Probability (LOLP), which is the probability of some generation shortfall over a specified period of time. The traditional utility standard for generation LOLP in the U.S. is 5 percent, or one event in 20 years. The results of this study show a likelihood of interruption almost five times higher than this traditional standard. In order to meet that standard, we estimate that it would require almost 3,000 megawatts of new generating resources by 2003. New resources could, however, be some combination of new generating capacity and voluntary load reduction. It is not clear whether additional generating capacity and load reduction are substitutable one for one. We are planning further

[2] The analysis here assumes that the aggregate level of operating reserves specified by the WSCC is met at all times. Curtailments can occur even if there is unloaded generation capacity, if use of that capacity would violate reserve requirements. Reserve requirements in any hour are equal to five percent of hydro generation plus seven percent of thermal generation, or the single largest contingency, whichever is larger. Reserves are to be maintained at these levels to prevent the transmission system from becoming unstable and causing widespread disruptions. Utilities are required to restore reserves to the specified levels in a short period of time and, if unable to do so, are required to shed loads. Consequently, we believe it is not justifiable to count use of operating reserves toward meeting demand.

analysis of this question. However, given the lead times for the development of substantial amounts of new generating capacity, it seems clear that much of this new capacity will have to be met through voluntary load reduction where reducing load makes sense for both the end-user and the system. The alternative is involuntary load reduction, where system operators are forced to allocate supply shortfalls through mechanisms like rolling brownouts or blackouts at the substation level without regard to the value different customers place on maintaining service.

The Region is Heavily Dependent on Imports

This analysis also highlights the importance of power imports, particularly over the next few years before substantial new resources can be added to the system. These imports are necessary both to serve loads and to help restore the hydroelectric system after it has been necessary to temporarily draft the system below non-power constraints to address adequacy problems. These non-power constraints are typically reservoir elevation requirements for salmon and resident fish mitigation. The level of imports is heaviest in fall and early winter, with average purchases approaching 2,500 average megawatts, primarily from California and the Desert Southwest. Individual years with poor water conditions would see higher levels of imports continuing though the winter. The addition of new resources within the Northwest reduces the levels of imports significantly.

This extensive use of imports is not unreasonable. The Northwest has been transitioning from a standard of regional self-sufficiency under critical water conditions for a number of years. It is more efficient for the region to take advantage of the seasonal diversity in loads that exist between the Northwest and the Southwest than to try to be self-sufficient in resources. Generating capacity used to meet high summer loads in the Southwest is often available to help meet fall and winter needs in the Northwest.

The high degree of reliance on imports does mean, however, that we are highly dependent on the interties and their reliability. Our analysis has not incorporated the effects of unplanned outages on the interties on our ability to meet Northwest loads.

The Region Will Have to Make Significant Use of the Flexibility of the Hydro System

There have been significant constraints placed on the operation of the Pacific Northwest hydroelectric system in recent years for the purposes of salmon recovery and mitigation of resident fish problems. Nonetheless, on a short-term basis (periods of a week or less), the system still retains a high degree of operating flexibility. System operators can, if necessary, temporarily take additional energy (water) out of the system to help meet supply problems. In periods of very high demand, after all available Northwest generation and imports have been used, it may still be necessary to draft reservoirs in the system below levels that would ordinarily be constraints, and use this emergency generation to meet demand. That water is replaced as soon as possible by reducing hydro system generation, continuing high levels of regional thermal operation and purchasing additional imports. This kind of emergency operation during cold snaps is explicitly recognized in the current Biological Opinion.[3]

Our analysis indicates that over the next few years, before significant new resources are added to the system, there is a high likelihood this flexibility will have to be used. Under most circumstances, this flexibility can be used without significantly affecting factors that are important to salmon recovery and healthy resident fish populations – reservoir levels and stream flows. The analysis showed relatively little

[3] **1994-1998 Biological Opinion on the Operation of the Federal Columbia River System**, National Marine Fisheries Service, Seattle, WA, Issued March 2, 1995; Supplement Issued, May 1998.

effect on flows but somewhat lower reservoir levels in dry years. In the near term, absent alternatives, this is something that the region may have to live. However, if, in the longer term, we do not add resources to the system, we would be forced to push the system harder and harder. This would lead to unacceptable impacts.

Market-Driven Generation Development May Not be Sufficient for Reliability

One of the more difficult aspects of this study has to do with how much of the generation needed for reliability purposes is likely to be brought on line over the next few years in response to market forces. The utility industry is in a new world compared to what existed just a few years ago. As a matter of national policy, the generation market has been opened up to competition. Development is being undertaken primarily by independent developers, many of whom are unregulated affiliates of utilities. These independent developers do not have monopoly service territories. They cannot count on being able to recover the fixed costs of new generating units from a secure customer base. They must be able to recover their costs and make a profit on the basis of what a plant can earn at market prices.

Adequately capturing the decision process of developers and their financial backers is difficult. We have used a commercial model, the AURORA™ Electric Market Model, to estimate the development of new, market-driven development.[4] AURORA uses an iterative process to forecast market prices and the viability of new (and existing) resources at those prices. The analysis is extremely data intensive, and many of the data requirements, like forecast fuel prices, technological advances, and price of load curtailment are open to argument. In addition, such an analysis cannot hope to capture the details of specific situations that might make particular projects more or less viable.

With those caveats, what the analysis suggests, first of all, is that even if the market would support it, the lead times for new development are such that it is not possible for significant amounts of new generation to come on line before 2002 at the earliest. Beyond that, the model indicates steady development of new generation in the Northwest beginning (coming on line) about 2004. However, this is not soon enough, nor in sufficient quantity to avoid the kinds of infrequent, relatively short-duration supply problems that this study identifies. The generation units that are added are primarily gas-fired combined-cycle combustion turbines.

We are not completely confident in these results. It may be that very high prices during periods of short supply could result in more development or development of a different type than our analysis suggests. It may also be that the market for ancillary services may have an effect on development that our analysis is not capturing. Moreover, it is certain that the modeling cannot capture the specifics of individual developer and project decisions.

There is the possibility that new mechanisms can be established to pay for new or existing capacity for reliability purposes. There is the risk, however, of giving unfair market advantage to some parties at the expense of others, thereby distorting the competitive marketplace. These questions need further analysis.

It's Time for Serious Discussion

The bottom line of this study is the Council thinks the Northwest needs to start serious discussions about how it can assure an adequate power supply during this transitional period in the electricity industry.

[4] AURORA Electric Market Model, EPIS Inc., 18813 Willamette Dr., West Linn, OR 97068, www.epis.com

The supply side needs to be an important component of these discussions. Does the region need to take special steps to support the development of generation for reliability purposes? If so, how? What is the cost? And what effects will this intervention in the competitive generation market have?

Given the impending potential supply problems, the demand-side needs to be addressed as well. Doing so may also be more economical than a pure supply-side approach. Many believe that as more end-users see market prices directly on a real-time basis, loads will automatically be reduced during periods of short supply and very high prices. We believe that will, in fact, be the case. Industrial and large commercial customers are most likely to see market prices and are probably most able to respond to price signals with load reductions or by shifting loads to off-peak periods. However, it is not clear how long it will take before real-time market prices will make it through to a large number of these end-users. Nor is it clear how long it will take for these end-users to implement procedures for load reduction or shifting in response to these prices.

In the near term, the region may have to look to other mechanisms by which the demand-side can participate in achieving load-resource balance. There are a variety of mechanisms that one could envision. They range from technological means of reducing and/or shifting loads to contracts for shedding loads or perhaps establishing a market for load reductions. Whatever the specific approach, there are criteria that should be met. The mechanism should be voluntary on the part of the end-user. Otherwise, we might as well rely on rolling blackouts. The mechanism should make economic sense for the end-user and the power system. And the mechanism must be reliable. The load reduction must be there when called upon. Otherwise, it cannot contribute to the overall reliability of the system.

Next Steps

Phase 2 of the Adequacy/Reliability Study has two components. The first is to explore the options for addressing the power supply adequacy problems this analysis has identified. These options are described below. The second is to further refine the analysis that has already been done. The steps to be taken there are described under "Results."

Options for ensuring an adequate power supply

Our analysis has indicated the need for substantial new resource development and/or voluntary (but dispatchable) economic load reduction in order to avoid power supply adequacy problems. The analysis also suggests that the market, as currently structured, may not be up to the task of ensuring adequate supplies. The market price signals to power plant developers do not appear to be sufficient to ensure adequate generation resources for the kinds of infrequent but potentially severe problems identified in this analysis. At the same time, relatively few end-use consumers see real-time prices that would allow them to make the trade-off between price and consumption that could mitigate supply shortfalls. The number of customers seeing real-time pricing is likely to increase over time but it is far from clear how quickly and to what extent that will happen.

The question is what to do about it. There seem to be two possible approaches:

Stand back and let the market develop

There is a school of thought that the best plan is no plan. Real-time pricing seems likely to become more prevalent with time, perhaps to an extent sufficient to mitigate supply shortfalls. If we do experience periods of inadequate power supply, system operators would manage through such situations. First they would purchase power wherever they could and at whatever price. If that proved insufficient, system operators would shed load, probably through rolling blackouts on the substation level so as to maintain the stability of the system as a whole. Those consumers who value uninterrupted service very highly might find it in their interest to invest in stand-by generation. The suppliers responsible for meeting load will see the high wholesale price of power during periods of tight supplies and also might find themselves subject to damages when they are unable to meet load. Those costs might be sufficient to encourage those suppliers to enter into interruptible contracts with some customers, invest in load shifting or load shaving technology and/or invest in standby generation. Emerging distributed generation technologies may help address local; distribution system reinforcement needs as well as help power supply adequacy. However, if the cost of avoiding interruption exceeds the cost of the interruption, from an economic standpoint, avoidance actions shouldn't be undertaken. This would all take some time to work out, but it would probably happen.

Jump-start the response.

Even if you believe the market will develop as described above, there are reasons why the region might want to begin looking at ways to mitigate supply shortfalls before they happen. Letting the market develop is inherently messy. The public is relatively tolerant of power interruptions that can be attributed to acts of God. They may be less tolerant of interruptions that they might attribute to a failure of trusted institutions to carry out their responsibilities. Their reaction might include a backlash that delays or even reverses the general movement toward a more competitive and efficient power system. It may be prudent to take steps to facilitate the development of responses to possible supply inadequacies before they happen. Some of the possibilities include:

- Find a way to pay the fixed costs of sufficient generation capacity to address adequacy problems. This capacity could either be new generation or older, less efficient generation that would otherwise not be available for use (however, little or no capacity in the Northwest fits this description). The regulatory approach is to require suppliers to maintain a planning reserve (of which operating reserves are a subset) adequate to achieve an acceptable loss of load probability. There are a number of different ways in which a reserve requirement might be implemented, some more and some less market-oriented.[5] The cost of maintaining that reserve margin inevitably flows through to the consumer in a way that does not distinguish between different consumers' cost of curtailment. The consumer pays the same whether uninterrupted service is very valuable or only modestly valuable. On the other hand, this inefficiency may be a minor factor in most consumers' consideration. As noted above, emerging distributed generation technologies might play a deal role in addressing local distribution system reinforcement needs as well as providing additional power supply.

- The other alternative is to find a way for the end-user to participate *voluntarily*. There are several ways in which this might happen.

    - Real-time pricing -- economic theory indicates that if consumers see the actual price of the power, they might choose to reduce their use in periods of extreme high prices. This is, of course, a highly charged issue. Many consumers may not wish to face volatile prices. On the other hand, it is not necessary to fully embrace retail open access to get some benefit out of real-time pricing. Some consumers may well be able to handle the volatility and welcome the opportunity to manage their electricity use in response to real-time price signals. These are most likely large industrial and, perhaps, commercial consumers. Reductions in those loads could have a significant effect on the adequacy of power

[5] See Hirst, Eric; Brendan Kirby and Stan Hadley, "Generation and Transmission Adequacy in a Restructuring U.S. Electric Industry," Prepared for the Edison Electric Institute, 701 Pennsylvania Av NW, Washington, DC 20004-2696, June, 1999, pp. 7-16.

supplies. How end-users would choose to respond to high prices could take any number of directions, ranging from reducing or stopping operations, investing conservation of demand management or investing in self-generation.

- Increased use of contracts for load reduction. In the absence of direct price signals to consumers, those responsible for serving loads might find it attractive to enter into contracts for load reduction with end-users. Theoretically, suppliers could pay up to the difference between the market price of power and their tariffed rate. These could be contracts for curtailment or load reduction between a utility and its customers or even with other power suppliers who might find it economic to meet reserve needs in this way. Some activities might offer opportunities for such load reductions are processes that, for a price, can discontinue operation temporarily. Candidates might be some of the Direct Service Industries, air separation, rock crushing, and other industrial processes. Some might be able to use backup generation. The rapid development and penetration of digital communications and control technologies should make it increasingly feasible to achieve controllable demand reduction.

- Demand-side bids to provide reserves. This would involve the same physical actions but a different market mechanism that once established could be more flexible and have lower transaction costs. Markets for load reduction are being established.[6] End-users get paid to reduce loads or take loads off the system with the payment based on the difference between the market price of power and the rate paid by the end-user.

- For other applications, it may be possible to employ Demand- Side Management technologies that can reduce the peak level of use, for example, reducing lighting levels in commercial buildings or water heaters that can be controlled remotely to reduce the coincident use of power for water heating. Again, as digital communications and control technologies evolve, the opportunities might be expected to expand. In each of these instances, at least a contractual relationship and perhaps the investment in some technology will be required.

- "Conventional" conservation. The Northwest has a long and successful history in implementing end-use efficiency improvements. Conservation is a resource that will reduce loads. While not as targeted at periods of critical supply constraints as some of the other options, conservation can clearly contribute. When assessing the value of conservation opportunities, their contribution to addressing power supply adequacy problems should be included.

What finally evolves will probably be some mix of the approaches depending on timing, economics and political feasibility. It may be that many of the demand-side actions turn out to be attractive economically. Phase 2 of the study will focus on working with parties in the region to evaluate the different options. What is clear is that there needs to be a focus on making something other than the involuntary curtailment option happen and happen soon.

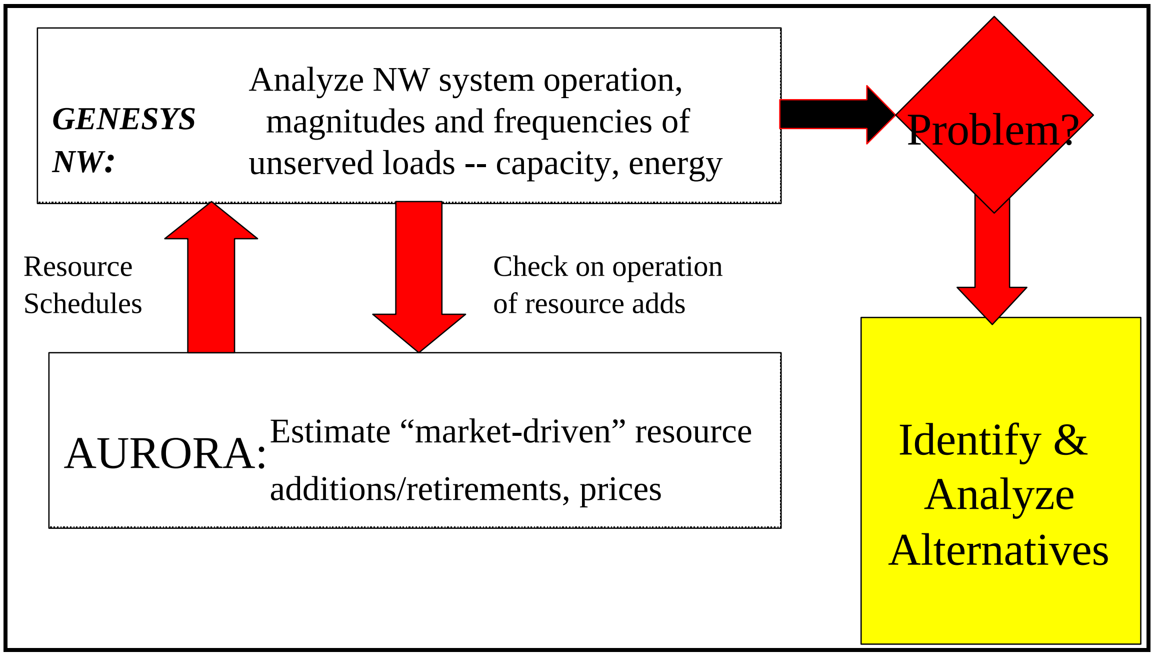
[6] Capage, Adam, Ron Davis and William Le Blanc, "The Dawning of Market-Based Load Management," E Source Report ER-99-18, E Source, 4755 Walnut St., Boulder, CO 80301-2537 pp. 9-10.

Analytical Approach

The analysis relies on two models of the Northwest and Western power systems -- *GENESYS* and AURORA. Their relationship is diagramed in Figure 1.

Figure 1

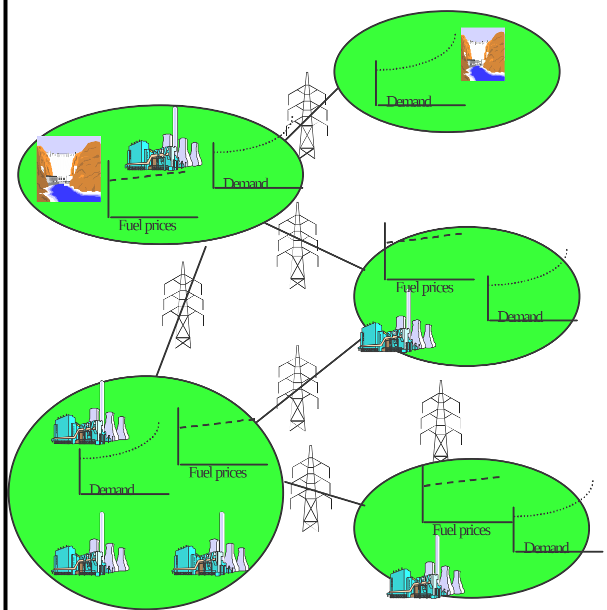
Overall Analytical Approach



AURORA

AURORA is a commercial proprietary model developed by EPIS, Inc. AURORA is used to provide *GENESYS* with schedules for the market-driven development of new resources and the retirement of existing resources and estimates of the availability of resources from other regions. A schematic of AURORA is shown on figure 2.

Figure 2
AURORA Schematic



15 load - resource areas
- transmission interconnections
- individual generating units (>2000)
- load forecast
- fuel price forecast
- portfolio of new resource options

Hourly market clearing prices
- by area and trading hub
- most expensive resource required to meet load for that hour

Resource retirements
- uneconomic going forward costs

Resource additions
- positive net present value

AURORA simulates the operation and expansion of the entire West Coast power system. AURORA is very data intensive. It operates off a data base containing the characteristics of existing and committed generating resources in the West, transmission capacity and costs between sub-regions, fuel price and demand growth forecasts, new generating resource characteristics (costs, efficiency), the cost of curtailing loads and a number of other factors. It incorporates a simplified representation of the operation of the hydroelectric generation in the West. The model runs multiple iterations to estimate market prices, the development of new resources and the retirements of existing resources until forecast market prices converge on stable values. Roughly stated, the decision rule is that those new resources that can cover their full costs and earn an acceptable return on their investment are built. Those that cannot are not built. If existing plants cannot recover their fixed and variable operating costs, they are retired, otherwise, they continue to operate. The model implicitly assumes perfect knowledge about the future – demands, fuel prices, what other plants are built and so on. That, of course, is a condition that cannot exist.

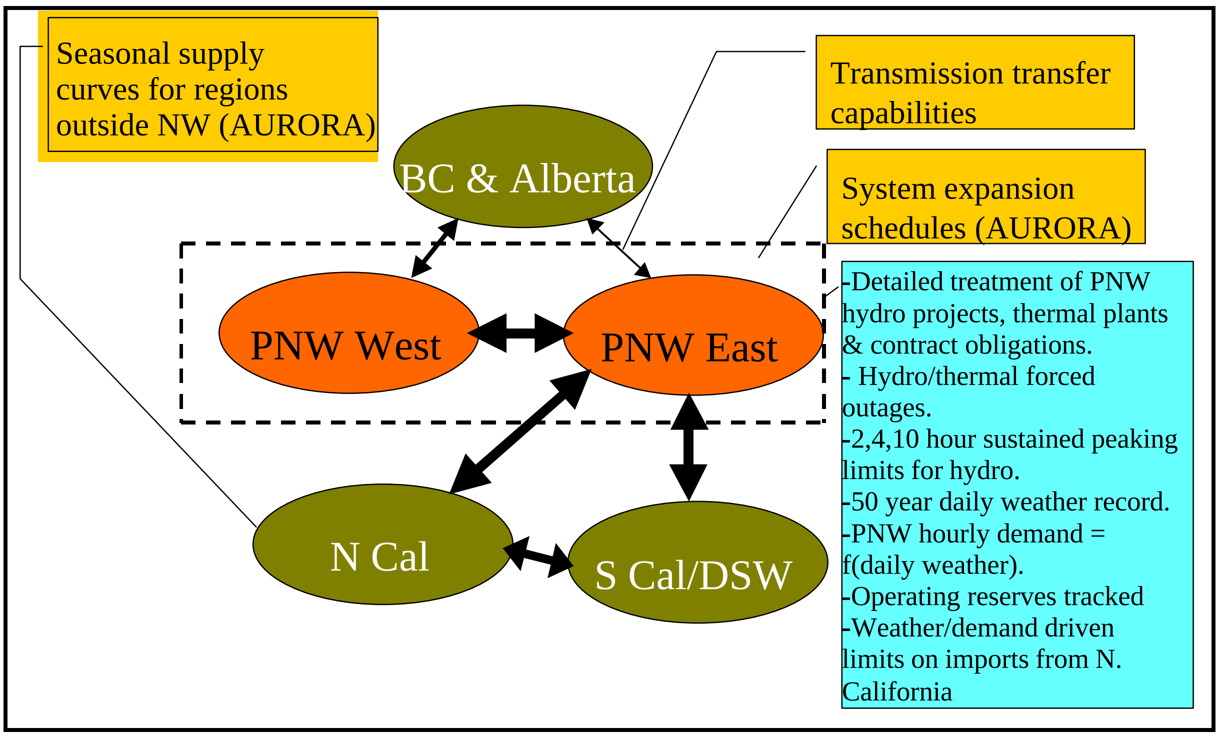
Because of computational limitations, it is necessary to make an assumption about hydro conditions when using AURORA in the resource expansion mode. For now, the assumption we have made is that developers would make their build decisions based on average hydro conditions. In poorer water years, a plant would make more money, in better water years it would make less. The assumption of average water was intended to represent a balancing of this uncertainty that developers face. However, prices are not entirely symmetrical around average water. We are investigating whether "slightly dry" water conditions should be used in subsequent analysis. In this respect and in others, the model cannot hope to fully capture how individual developers would make the build decision or the details of “deals” that might make a specific project go or not go.

GENESYS

GENESYS is the model used in this study for evaluation of power supply adequacy. It focuses on the Pacific Northwest region as defined by the Northwest Power Act. This includes the states of Idaho, Oregon, Washington and Montana west of the Continental Divide. The Pacific Northwest region is divided into a Western section and an Eastern section. This allows the capture of the possible effects of transmission transfer limits east to west and to model limitations on the transfer capability from Northern California to the Northwest as a function of demand and generation on the west side of the Cascades. The structure of *GENESYS* is highlighted in Figure 3.

Figure 3

***GENESYS* Area Structure**



One of the roles of *GENESYS* is to represent the important sources of uncertainty in generation supply, allowing their effect on the adequacy of power supply to be captured probabilistically. This is done in *GENESYS* through a technique known as Monte Carlo simulation. In *GENESYS*, a single simulation is performed by taking samples for uncertain variables from defined probability distributions, and then simulating the operation of the power system under those conditions. Hundreds of simulations (or games) are run with different observations for these uncertain variables to evaluate the full range of impact on the ability of the system to meet load. The primary uncertain variables in *GENESYS* are Pacific Northwest stream flows, Pacific Northwest demand and generating unit forced outages. The variation in stream flow is captured through incorporation of the 50-year (1929–1978) Pacific Northwest streamflow record. Uncertainty in demand is captured through use of a weather-driven demand model. *GENESYS* incorporates an hourly demand model for the Pacific Northwest that uses observed daily average temperatures to calculate hourly demands. Here, the daily temperature record corresponding to the 50-year stream flow record is used. The temperature record can either be run in lockstep with the streamflow record (i.e., 1929 water and 1929 temperatures go together) or the temperature record can be sampled independently from streamflows. On average, this analysis assumes loads in the region grow at a rate of 1.5 percent per year. Finally, forced (unplanned) outages of thermal and hydro generating units are also a major source of uncertainty. The model samples the outage states of individual generating units according to their defined forced outage rates.

Another important role of *GENESYS* is to achieve a realistic representation of operation of the Pacific Northwest hydroelectric system. Hydro projects provide about 75 percent of the Northwest's electricity generation, and modeling realistic limits to hydro generation in emergency situations is critical to assessing system reliability. There is significant short-term flexibility in how the hydro system is operated, and a static treatment of Northwest hydro generation, as used in AURORA and other models, is insufficient for a power supply adequacy study for the Northwest. Energy generation at specific projects is discretionary within limits, and the capacity availability and duration (how long the system can generate at a given capacity) is a function of reservoir contents at any given time, releases at individual projects, the states of individual generators and a number of other factors. A detailed multi-project hydro-regulator is needed to track the system and determine the generation capability at any observed state. *GENESYS* incorporates the current version of HYDSIM, the hydro-regulation model used by the Bonneville Power Administration. Use of a multi-project hydro-regulator also provides the ability to evaluate the trade-offs between operating the system for reliability and strict adherence to fish and wildlife constraints. Finally, the relationship between daily average hydro energy generation and sustained peaking capability for each of 2, 4, and 10-hour duration limits is modeled using functions developed through the trapezoidal approximation linear program. This methodology is described in the Technical Appendix of the Council's Fourth Northwest Power Plan.[7]

In addition to draft of U.S. projects, Bonneville also has seasonal access to generation from storage in Canadian projects through non-treaty storage and provisional draft agreements. The use (and restoration) of this storage is modeled in *GENESYS*.

In the reliability analysis, transfer limits on the interties into the Northwest are generally held constant, with two exceptions: first, the south-to-north capacity of the California-Oregon Intertie, connecting the Pacific Northwest and Northern California, is an inverse function of net demand (load minus generation) on the west side of the Cascades. When net west-side demand exceeds 11,000 megawatts, the transfer limit begins to drop from a maximum of 3,705 megawatts and if demand continues to rise, the line may be derated to as low as 1,300 megawatts. This relationship is modeled in *GENESYS*, using data supplied by Bonneville.

Second, it was found that there are circumstances when both the Northwest and Northern California are experiencing colder than normal weather simultaneously. When it gets cold in Northern California, the potential for imports through Northern California is reduced because of increased load there and natural gas supply constraints. Based on discussion with California Energy Commission and Pacific Gas & Electric staff, it was estimated that when temperatures in Northern California fall to 50 degrees, the availability of imports out of Northern California begins to fall, reaching zero at a Northern California temperature of 40 degrees. A temperature record for Northern California parallel to the record for the Northwest was incorporated in the model and import availability from Northern California is adjusted based on the observed daily temperature there.

[7] Northwest Power Planning Council *Fourth Northwest Conservation and electric Power Plan,* Volume II Technical Appendices, Appendix H2, July, 1998.

To determine generation sufficiency for the region, *GENESYS* performs a chronological, multi-area, transmission-constrained dispatch. This dispatch is carried out on a subdaily basis down to hourly if desired. As mentioned above, Pacific Northwest resources and loads are modeled at a high level of detail. Contract export obligations of the Northwest are always met, and it is likewise assumed that contractual imports from other areas are always supplied. For this analysis, individual resources outside the region (Northern California, Southern California and the Desert Southwest, British Columbia and Alberta) are not modeled in detail. Surplus generation from these areas, that would be available for import to the Northwest, is represented by a set of supply curves (amounts of power available at a given price) that are differentiated seasonally and by time of day. The results from AURORA runs were used to estimate these supply curves. When necessary, generation in the other regions is used first to offset any firm export obligations from the Northwest (counter-scheduling) and then for imports to the Northwest.

In the results presented here, the full flexibility of the hydro system is used to meet load if required. If necessary to meet Pacific Northwest demand, reservoirs are drafted below non-power constraints. These are typically reservoir levels at particular times of the year established to ensure the ability to provide desired flows for downstream migration of salmonids. This flexibility is used only as a last resort after hydro above fish constraints, thermal generation, imports, hydro from non-treaty storage, and provisional draft of Canadian reservoirs (Arrow). This water is restored as soon as possible by running thermal units more than normal and by making additional imports. The cost of these operations is not estimated.

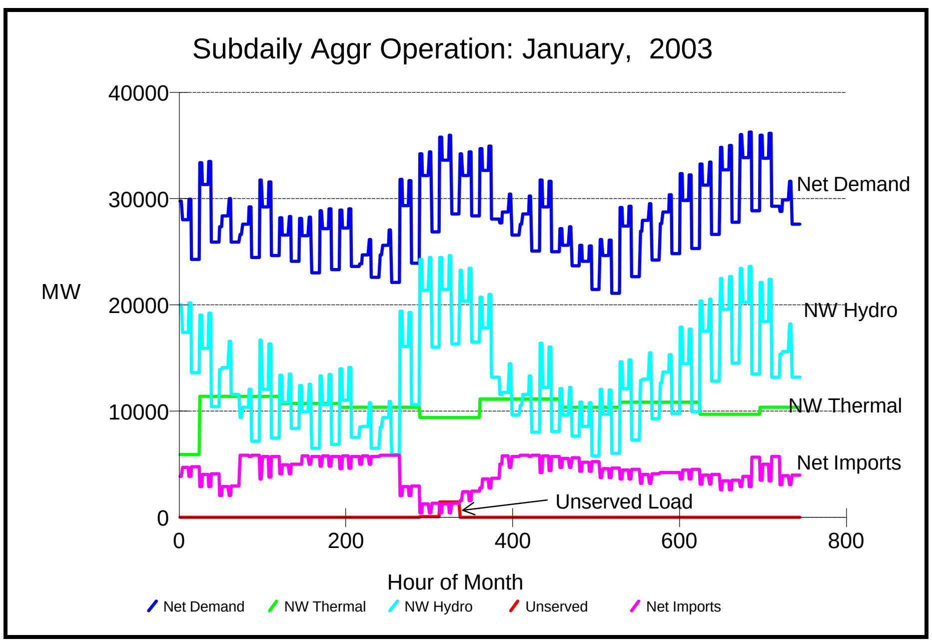
Results

Power Supply Adequacy

Initial analysis found that if problems of power supply adequacy were to occur, they would occur during the winter months when Northwest loads peak. Consequently, the analysis focused on the months of December, January and February. As noted earlier, *GENESYS* is a Monte Carlo simulation where many individual simulations or "games" are run in which the uncertain variables – stream flows, temperatures, and forced outages – are sampled according to their probability distributions. In this study, the model was run on a daily time step over each winter season, with each day broken into four demand segments – a morning peak, a mid-day period, an evening peak and a night-time off-peak period. For this part of the analysis, no additional generating capacity was assumed for the region beyond the Klamath Falls cogeneration units (536 megawatts) that are already under construction.

Figure 4 illustrates of one such game for January in 2003. In this particular game, the stream flow and temperature conditions correspond to 1932 water and 1950 weather conditions respectively. This is a poor streamflow year and a weather year in which two cold snaps occur in January.

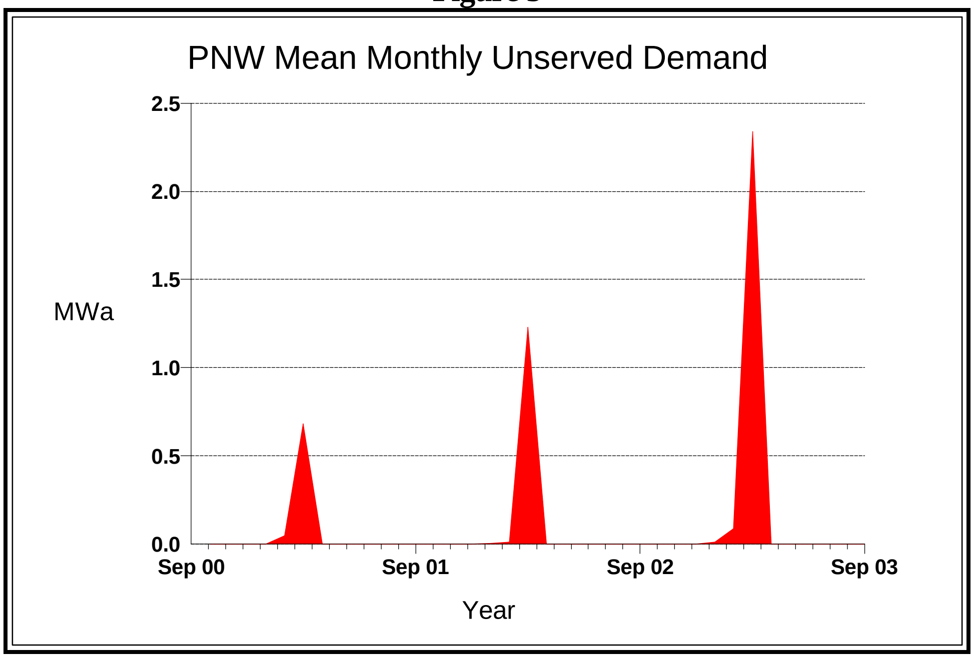
Figure 4
Subdaily Aggregate Operation for January, 2003
1932 Stream Flows and 1950 Temperatures



The top line shows the variation of net demand over the month, with two distinct periods of high demand (cold temperatures) occuring just before mid-month and toward the end of the month. The second line down shows the output from Northwest hydro. This clearly illustrates how hydro is used to follow daily variations in load, and a heavier use of hydro during the cold-snaps. The third line down shows the operation of Northwest thermal units. This is a month when regional generation supplies are tight, and all thermal units are running if not on forced outage. The dips in the thermal line correspond to forced outages on some of these units. The fourth line down shows net imports. This shows that for much of this month, use of imports is on the order of 6,000 megawatts. During the first cold snap, imports fall off sharply. This corresponds to coincident cold snaps in the Northwest and Northern California which limit the availability of imports. Hydro picks up much of the swing, but even with use of non-treaty storage and provisional draft from Canadian projects, not all demand can be met. During this period, the Northwest experiences unserved load (the bottom line) on the order of 1,000 to 1,500 megawatts for a period of approximately a day. During the demand surge later in the month, there is no corresponding cold snap in Northern California and the level of imports is maintained and there is no unserved load.

Figure 4 shows the results for a single game for a single month. Figure 5 shows the ***mean*** unserved demand for 500 games for the operating years beginning September 2000 through September 2003. In these games, water years and temperature years were selected sequentially from the historical record and run in lockstep mode.

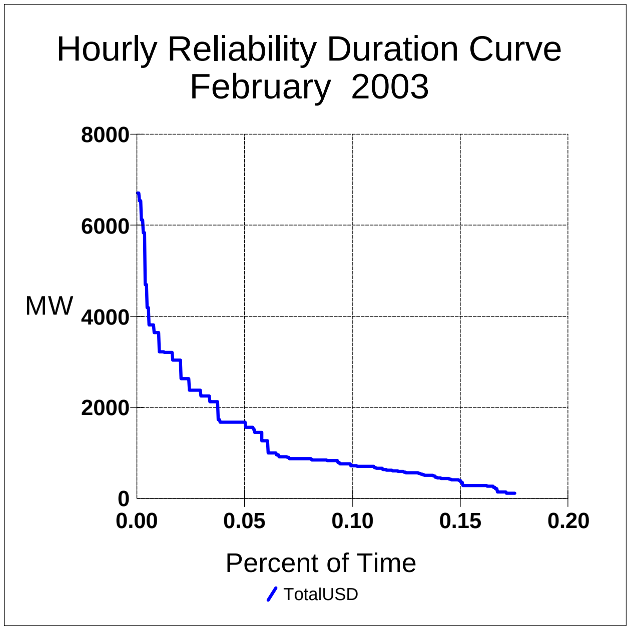
Figure 5



As Figure 5 shows, on an average basis, the problems appear to be quite small. The mean unserved demand in February 2003 is under 2.5 average megawatts for a monthly average demand of over 20,000 average megawatts. Use of the mean is very misleading, however, because it includes the results for over 330,000 hours simulated in each month, the vast majority of which have zero unserved demand. This masks the magnitude of the relatively small number of individual reliability events that occur in February.

A graphic that provides better insight into the generation reliability problem is shown in Figure 6. This is a duration curve of the hourly unserved demand events for all hours simulated in February 2003. All of the reliability events recorded in the simulation are sorted from high to low and plotted against their cumulative probability. The chart provides an indication of both the magnitude and probability of unserved demand events. The figure shows that for over 99.8 percent of the 336,000 hours examined there was no reliability problem detected. However, for almost 0.2 percent of the hours there was some level of unserved load. For approximately .01 percent of the hours there was unserved load of 4,000 megawatts or more.[8]

Figure 6
Duration Curve of Unserved Demand

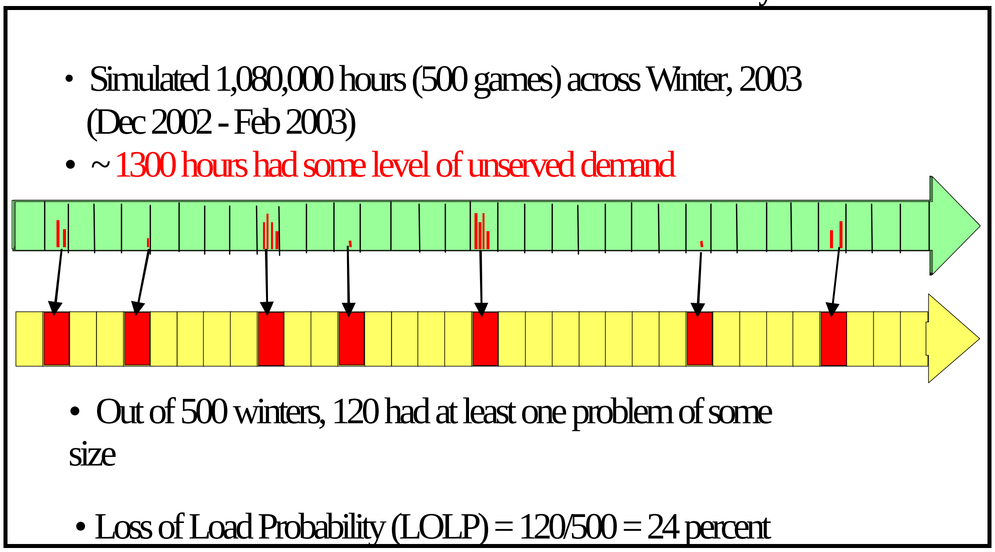


Loss of Load Probability

While the data of Figure 6 give a more detailed look at the simulation results, they can be difficult to interpret. Another way to express generation reliability is through a measure called "loss of load probability" (LOLP). This is a measure that has been commonly used by electric utilities historically. It represents the probability of any generation supply shortfall, regardless of magnitude, over some defined period of time, typically a peak day or peak season. We have chosen to look at an LOLP for the Pacific Northwest for the months of December through February. This asks the straightforward question: "What is the probability of a generation shortfall, of any size, across the winter months?" The determination of winter loss of load probability is illustrated on Figure 7.

[8] The flat spots on the curve in Figure 5 typically result from a day (24 hours) where there is insufficient energy available to meet average daily demand.

Figure 7
Determination of Loss of Load Probability



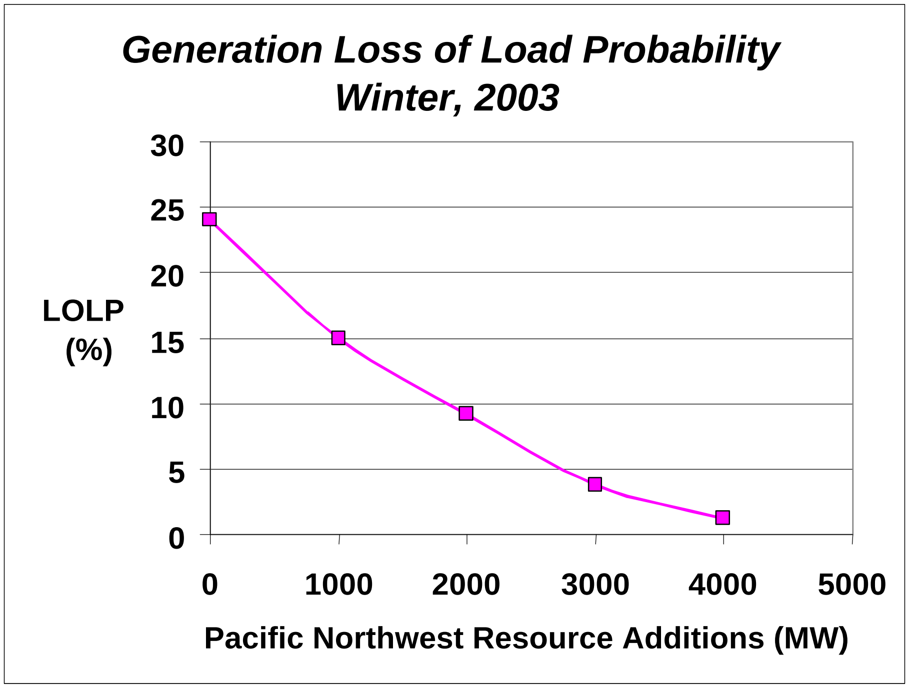
In 500 games, the *GENESYS* simulation examined over a million hours across the winter months of 2003. In approximately 1,300 of those hours there was some level of unserved demand. However, it would be incorrect to interpret that as a 0.12 percent probability of unserved load. Instead, think of each of the segments in the top arrow of Figure 7 as representing a winter. Within that winter, there might be one or more events in which resources were insufficient to meet load or there might be none at all. Such events are indicated by the "tics" within a winter. The events could be large in magnitude and/or duration or they might be small. If there is one or more event within a winter, that winter is counted as a "problem" winter, as indicated by the solid segments in the lower arrow. Out of 500 winters simulated, 120 had one or more events. The loss of load probability is then 120/500 or approximately 24 percent. This translates into an almost one in four chance of supply interruption in any given winter.

New Resource Needs

As mentioned earlier, the council believes a loss of load probability of 24 percent is unacceptably high. The next step in the analysis was to determine the amount of new resources necessary to reduce the loss of load probability to a more acceptable level. We have chosen a figure of 5 percent or essentially a one-winter-in-20 chance of losing load due to inadequate resources. This is a standard that has been used historically by utilities and their regulators.

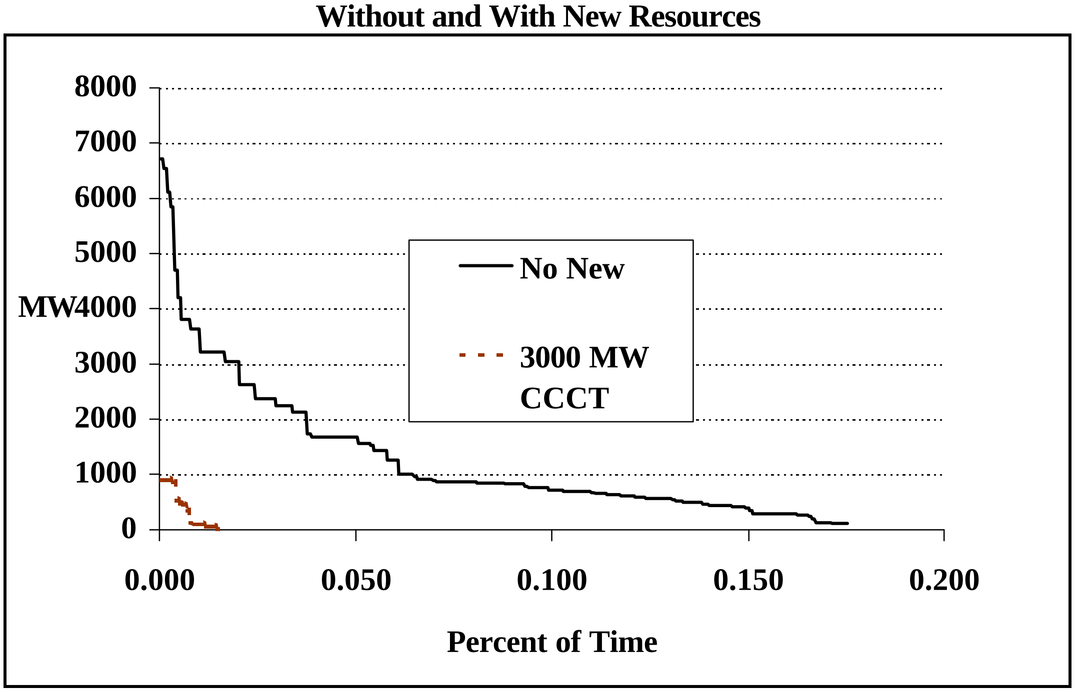
To assess the amount of new resource capacity required, additional amounts of capacity were added to the system incrementally and the probability of loss of load was reassessed. The resources added were all gas-fired combined cycle plants. The results are shown on figure 8. The analysis indicates that approximately 2,800 megawatts of generating new resource capacity would be required to bring the probability of loss of load down to 5 percent. We have not yet assessed the degree to which generation and load reduction are interchangeable. Generation capacity, which can be run at times other than when a supply shortfall is imminent, probably helps keep the hydro system up and may have greater effect on reducing the LOLP than an equivalent amount of load reduction. This relationship will be investigated in Phase 2.

Figure 8



The effect of adding 3,000 megawatts of combined cycle on the hourly duration curve of unserved load for February, 2003 is illustrated in Figure 9. The chart on the left is a repeat of Figure 6. The chart on the right shows the effect of the resource additions. The new resources reduce both the probability and the magnitude of curtailment by roughly an order of magnitude.

Figure 9
Comparison of Hourly Unserved Load Duration Curve
Without and With New Resources



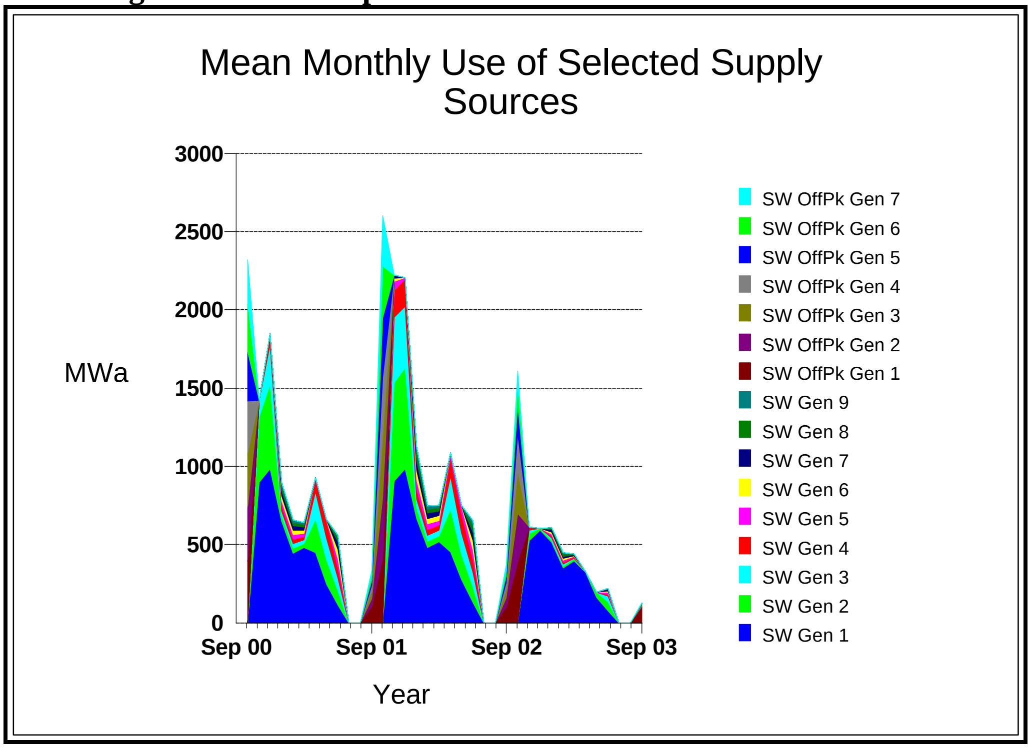
Imports

The region is heavily dependent on imports, primarily from California and the Desert Southwest, both for meeting load and for helping restore water in the hydro system after it has been necessary to draft below fish and wildlife targets to meet loads. The assumptions for import availability in GENESYS were developed through the area specific load and resource data we used in AURORA, including the effect of expected thermal maintenance and forced outage. The period during which imports into the region are most likely to be needed runs from September through March. In September, it is likely that only off-peak capacity would be available from the Southwest. Based on the AURORA data we've estimated that 7,000 megawatts are available in September off-peak hours. However, from October through March, there appears to be significant energy available around the clock, over 9,000 average megawatts available from the combined areas of the Desert Southwest, Southern California and Northern California. This is typically enough surplus to counter-schedule out of any Northwest contractual exports to the South, and still load the interties to their northbound transfer limits. So effectively, the limit on imports from the Southwest during the late fall and winter is the transfer capability of the interties. (However, as described earlier, the transfer capability of the AC is dynamically constrained by demand west of the Cascades, and/or cold snaps in Northern California.) A similar analysis for British Columbia and Alberta yields much smaller import capability. We have assumed surplus available from Canada equal to 380 and 290 average megawatts in September and October respectively. The analysis shows no availability in the winter months.

Figure 10 illustrates the average use of imports from the Southwest over the period September 2000 to August of 2003. The different shades represent blocks of power available at different prices, on and off peak. These results incorporate the effects of the addition of 3,000 megawatts of new generating capacity beginning in September of 2002 (the beginning of the 2003 operating year).

As this figure shows, imports are used heavily in the fall and again in the early spring to restore reservoir levels. The addition of the 3,000 megawatts of generation in Operating Year 2003 significantly diminishes the use of imports but does not eliminate it. It should also be emphasized that these are *average* levels. During periods of poor water conditions, exports are much higher and continue through most of the winter. Conversely, during wet years imports are less.

Figure 10
Average Reliance on Imports from California and the Desert Southwest



It should also be noted that the effect of new resources on the level of imports will depend on what kinds of new resources we are talking about and, more to the point, their cost relative to the cost of imports. Figure 10 incorporates the effects of 3,000 megawatts of new gas-fired combined cycle combustion turbine capacity beginning in operating year 2003. The cost of power from these units will displace more expensive imports. If some or all of the new resources were priced higher than some of the import blocks, then the imports would continue to be used.

In any event, imports are important to the region and will remain so. This is not a bad thing. It is merely the consequence of rational economic choices. It does, however, point out the importance of the interties. We have not incorporated any consideration of forced outages on the intertie in our assessment of power supply adequacy. There have been circumstances over the past decade that have reduced the transfer capability of the intertie, sometimes for extended periods.

Simulating February 1989

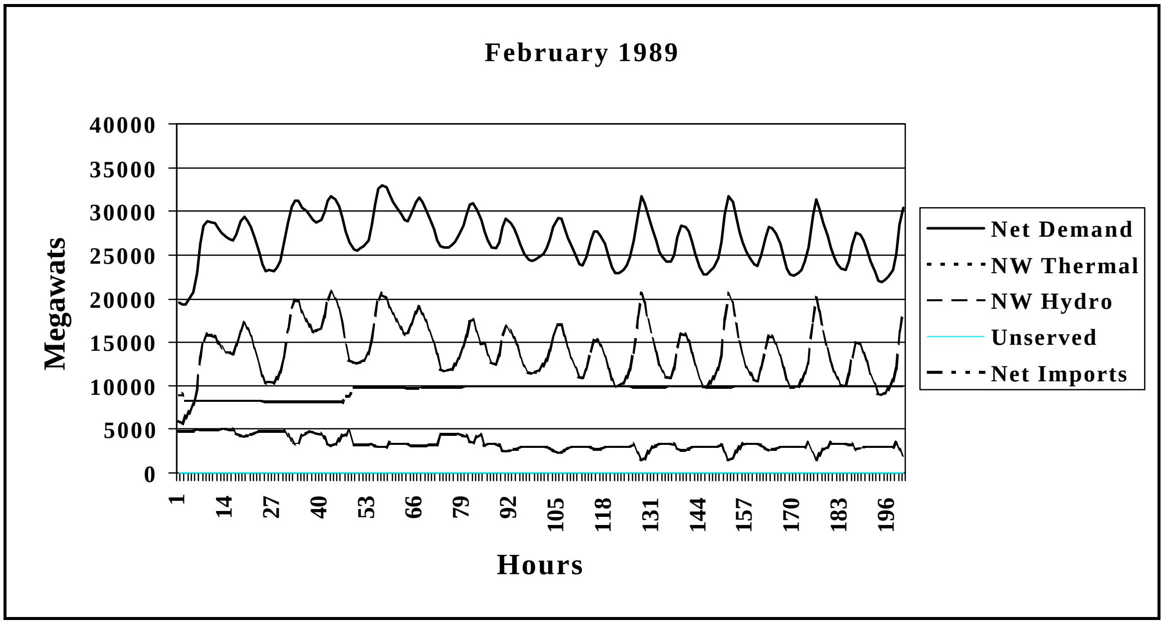
AS a test of *GENESYS,* a "backcast" of February 1989 was carried out. February of '89 was chosen because it is the most recent really severe situation that the region has faced. Although now more than a decade has passed, this event seems quite fresh in the memories of system operators. In the first few days of February '89, the region experience several days in which temperatures were quite low – 30 degrees F below normal in the region's load centers. Weather this cold has approximately a one in ten chance of occurring each winter.[9] Moreover, the cold was widespread throughout the region. Peak demand for the Northwest Power Pool exceeded the previous record by 5400 megawatts. In addition, reservoirs were quite low as a result of low stream flows and earlier operating decisions. The DC intertie was down beginning February 4. Finally, the month began with two major thermal units, WNP-2 and

[9] "Lessons Learned from the Cold Snap of February, 1989," Division of Power Supply, Bonneville Power Administration, April 26, 1989.

Colstrip 3, off line until the evening of February 2. The region made it through this event, but with a slender margin over operating reserve requirements. For the area modeled by *GENESYS* , the margin was approximately 300 megawatts.[10]

To test *GENESYS* , the model was run with actual February '89 loads and the 1989 resources from the 1989 Pacific Northwest Utilities Conference Committee Northwest Regional Forecast. The reservoirs were started where they were on January 31 and actual thermal unit outages were "hardwired" in the model. The operation of the hydro system was as modeled by *GENESYS.* The results are shown on Figure 11A for the first 200 hours of the month. Figure 11A shows that the region gets through the period with no unserved load.

Figure 11A



To see how close to the margin the simulation was, it was re-run with the loads incremented by an average of 500 megawatts over the month. The results are shown in Figure 11B.

[10] "Northwest Power Pool Operations During February 1989 Arctic Cold Weather Conditions," Northwest Power Pool Coordinating Group, march, 1989.

Figure 11B

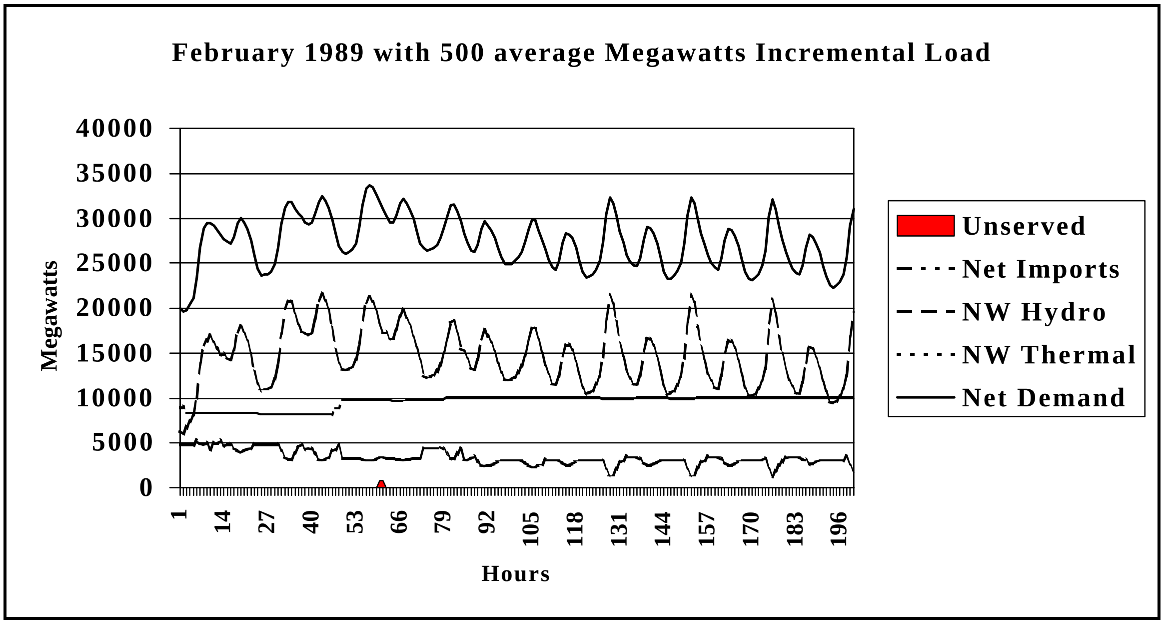


Figure 11B shows a short period of unserved peak load during the third say of the month amounting to a few hundred megawatts. This agrees quite well with the level of operating reserves available on that day.

February '89 Conditions Projected onto 2001

What would the situation be if we experience 1989 temperatures and water conditions with today's loads and resources? To test this, actual February '89 hourly loads were scaled up to 2001 with an average annual growth rate of 1.36 percent. Resources were updated to account for the resource additions and retirements that have occurred. For example, the Trojan nuclear power plant has been retired, the firm energy capability of the hydro system has been reduced as a result of fish requirements and several combined cycle combustion turbines and some renewable resources have been added to the system. The same forced outages of thermal units experienced in '89 were simulated as were the January 31 '89 reservoir conditions. Because of reinforcement of the DC intertie, it was assumed that the intertie would stay in service throughout the period. The results are shown on Figure 12.

Figure 12

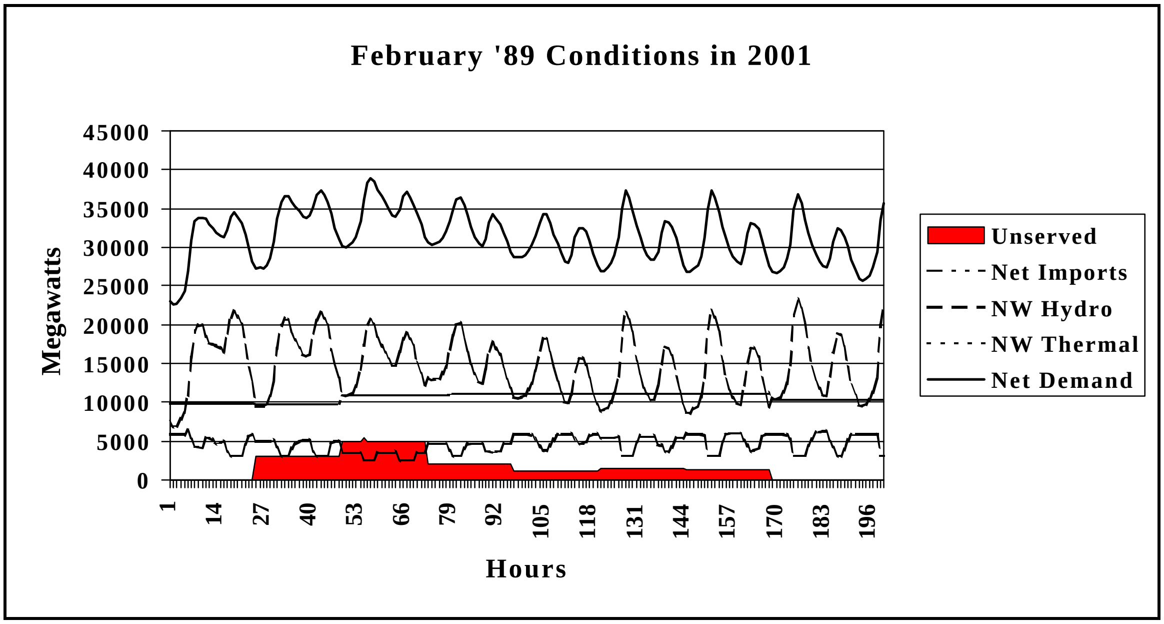
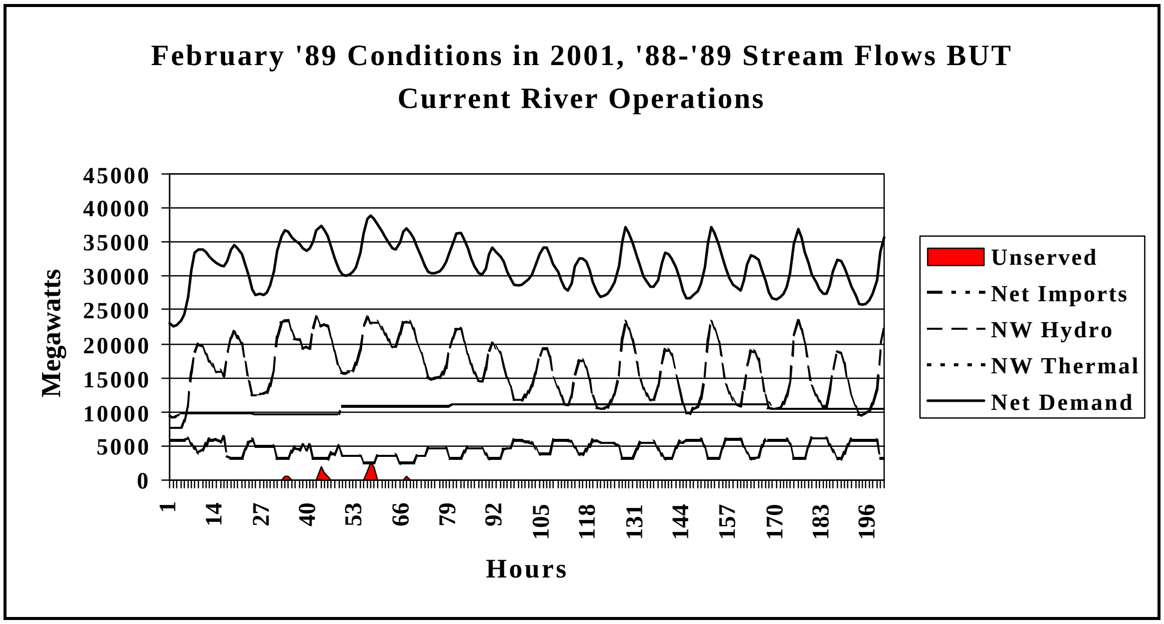


Figure 12 shows that if the same conditions were imposed on today's system, we would experience a significant and prolonged energy shortfall. The net addition of approximately 2000 megawatts since 1989 would be overwhelmed by the growth in loads.

However, this situation is probably unrealistic given the requirements of today's river operations. Because of the requirement to provide summer flows for salmon, we think it is unlikely that today's operators would allow reservoirs to be drafted as low as they were in in the fall of 1988 and early winter of 1989. The targets in the current Biological Opinion are for reservoirs to be at flood control throughout the winter, To achieve this in a year with low stream flows, operators would run thermal plants harder and made additional purchases of imports throughout the fall and early winter. To test this hypothesis, we ran the previous simulation, beginning the opeating year with the reservoirs as thery were at the end of August of 1988. We used '88-'89 stream flows with the current operations of the hydro system. The results are shown on Figure 13.

Figure 13



As this figure shows, the amount of hydro generation that we get during the period of highest demand, is approximately 4000 megawatts greater than shown on Figure 12, As a result, the severe energy deficit observed in Figure 12 is transformed into a couple of significant but much smaller peaking problems. There is, of course, a cost to this operation that we have not evaluated. However, in this instance, there is also a significant benefit to the power system.

Questions Requiring Further Analysis

We have fairly high confidence that the analysis is giving a reasonable representation of potential power supply adequacy problems. There are, however, factors that deserve further analysis that could alter the results to some degree. These questions will be addressed during Phase 2 of the study. They include:

- Cross-Cascades transmission transfer capability – We have estimated that during a winter event, the East-to-West cross-Cascades transfer capability would not be limiting. If, on further analysis, it turns out to be a limiting factor, the frequency and magnitude of supply problems would be larger.

- Intra-month stream flows – The analysis uses monthly average natural stream flows (the shortest time step currently available in the hydro-regulation model) and does not include the effects of reduced unregulated side flows into the reservoirs during extreme cold events within a month. This could exacerbate problems during extreme cold events.

- Availability of imports from Canada – We have assumed that during cold events, British Columbia and Alberta will also be experiencing increased demand and will not have significant exports available for our use. If there were emergency operations that could make Canadian power available, it would reduce the magnitude and frequency of supply problems here.

- Hydro generating unit forced outages and maintenance – While *GENESYS* has the capability of simulating hydro forced outages, further work needs to be done to separate the effects of forced outages on hydro units from deferrable maintenance. This study used an average availability for hydro units, based on the combined effect of forced outage rates and expected maintenance. To the extent that hydro unit maintenance is deferrable, it could be delayed if a cold snap were forecast, and would improve the reliability results in this study. On the other hand, full simulation of hydro unit forced outages would tend to decrease reliability. It is not clear at this time what the direction of the net effect would be. Work is ongoing to separate the effect of hydro unit forced outage and deferrable maintenance.

- Effect of additional generation versus load reduction in reducing LOLP – As noted earlier, our assessment of the amount of new resources needed to reduce the loss of load probability to 5 percent assumed the addition of combined cycle combustion turbines. It is likely that demand reduction or, for that matter, other generating technologies with different characteristics would interact with the hydroelectric system differently. As a consequence, it may not be possible to mix demand reduction and different kinds of generation on a megawatt for megawatt basis and achieve the same effect on LOLP.

In the longer term, there are a number of enhancements to *GENESYS* that will make it a more useful tool for the analysis of power supply adequacy. In approximate order of priority, they are as follows:

- Enhanced economics – At present, *GENESYS* incorporates only a relatively rough representation of the economics of operation of the Northwest power system including its interaction with other areas of the WSCC. To adequately evaluate the economics of different system operation alternatives will require simulating demands and resources not only in the Northwest, but also in the connected areas of the WSCC. This simulation does not need to be as detailed as exists in models like AURORA but is essential if the economics of various operational alternatives are to be evaluated.

- Shorter time periods – At present, *GENESYS* simulates hydro conditions over 14 periods in a year (the months of April and August are split, the rest of the months are whole). The stream flow data exists to allow simulating over 24 periods. This would yield a better representation of hydro generation.

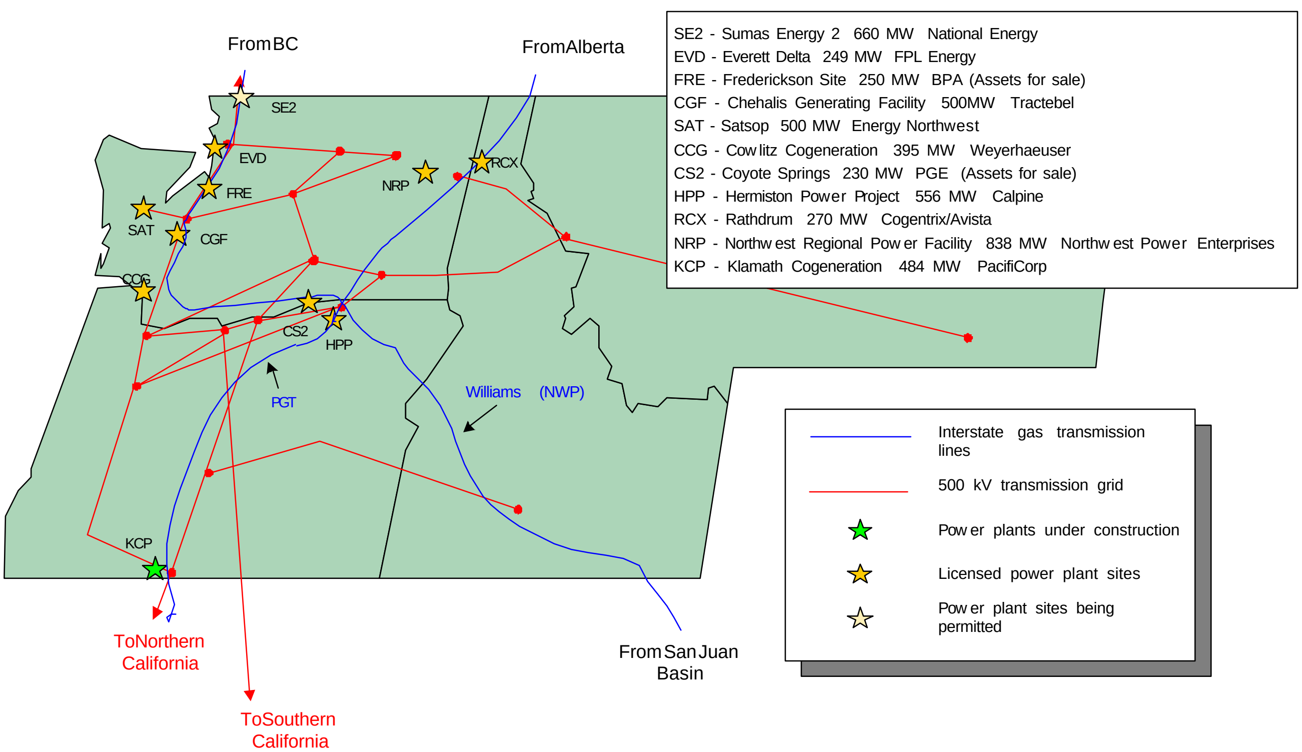
- Random water – *GENESYS* currently treats year-to-year variations in hydro conditions by going through the 50.years of the historical record sequentially multiple times. That is, the first game begins with 1929 water and proceeds through the record in sequence. The second game will begin with 1930 water and proceed through the record in sequence, and so on until the simulation has begun with each of the years in the record several times. Because there is relatively little correlation in water conditions from year to year, it would be preferable to be able to treat water conditions randomly. This will require some enhancements including determining the operation of Canadian dams dynamically.

New Power Plant Development

As the foregoing analysis shows, significant amounts of new resources are required to bring the loss of load probability down to a level consistent with our interpretation of industry standards. We now have a competitive generation market in which new generation development is typically undertaken by independent (non-regulated) developers. We would expect some part of the needed new resources to be supplied by new generation developed in response to market forces. The question is how much?

The Council maintains an inventory of existing generating projects and new project proposals. This provides us with an understanding of the type, location and size of new projects that could be constructed in the Pacific Northwest. What is uncertain is how many of these projects might be built and when they might enter service. Figure 14 shows the location of proposed projects in relation to the major natural gas pipelines and the transmission grid. All of the proposals are for natural gas-fired, combined-cycle combustion turbines, and range in size from about 250 to over 800 megawatts. Of these projects, only one is actually under construction – the 484 megawatt Klamath Falls Cogeneration Project in southern Oregon. Construction permits have been secured for the rest, save one. These permitted sites are capable of accommodating about 3,700 megawatts of new capacity. A site certificate for a 660 megawatt project is being sought for the remaining site.

Figure 14
Proposed Northwest Power Plants



As described earlier, we have used AURORA™, an electricity market model of the western North America power system developed by EPIS, Inc., to forecast market-driven resource retirements and additions. AURORA was developed primarily to forecast wholesale electric power prices. Because wholesale electricity prices are expected to drive development (and retirement) of generation in an increasingly deregulated generation market, AURORA can also be used to forecast the development (and retirement) of generating resources.

We modeled the Western Systems Coordinating Council (WSCC) electricity system as 15 geographic load-resource areas. These load-resource areas are generally defined by transmission constraints. Each area is characterized by an inventory of its existing generating units, fuel price forecasts, a load forecast, and a portfolio of new resource options. Transmission interconnections between the areas are characterized by transfer capacity, losses and wheeling costs.

Because we are interested in where in the Northwest development might take place, not just how much and when, we have chosen to model the Pacific Northwest as four load-resource areas. For this analysis, we have divided AURORA's standard single Washington/Oregon area into two areas – West of the Cascades and East of the Cascades. This was done in anticipation of the possibility that transmission across the Cascades could be constraining. The remaining two Northwest load-resource areas are southern Idaho and Montana.

AURORA forecasts hourly market clearing prices by dispatching generating units to meet forecast load-resource area loads. Unit dispatch is based on the variable cost of unit operation. Area loads may be served by native generation, or, if economic considering transmission capability, units located in other areas. Hourly electricity prices are established for each load-resource area by the variable cost of the most expensive resource dispatched to meet that area's load.

A forecast of generating unit retirements and additions is developed through an iterative process, in which the present value of candidate resource additions and retirements is calculated for each year over the study period. Existing resources are retired if market prices are insufficient to meet future maintenance and operation costs. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, maintenance and operation, including a return on the developer's investment.

Key Assumptions

Because independent generating companies are the primary developers of new generating resources, we assume that future projects will be developed under financial conditions representative of this type of developer. These financial assumptions are described in Appendix A. We assume that projects currently under construction are completed as scheduled, and that proposed retirements reported by WSCC occur as scheduled. These scheduled additions and retirements are listed in Appendix A. Additional project development and retirements are market-driven, as forecast by AURORA.

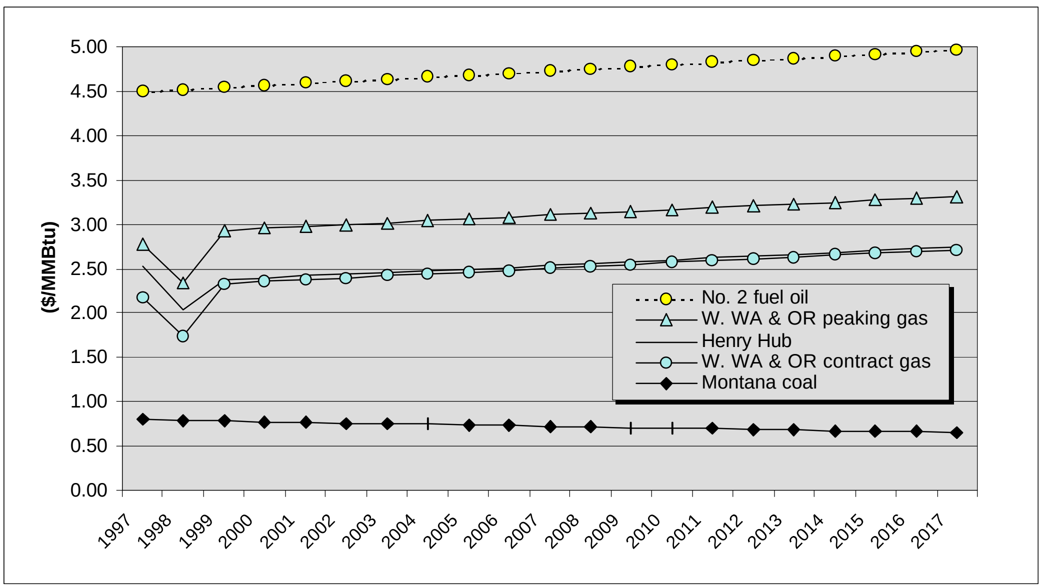
The findings described in this report are based on average water conditions from 1929 through 1978. Hydropower conditions can strongly affect wholesale electricity prices. It appears that the relationship is somewhat asymmetrical because price increases during poor water conditions are greater than the decline in prices under good water conditions of equal probability. However, this effect may be offset by greater price volatility observed in several good water years. Because long-term system expansion analysis using stochastic modeling of water conditions is very time consuming in AURORA, we are exploring the magnitude of price asymmetry and whether "slightly dry" water conditions should be used when forecasting wholesale prices.

Loads are also treated deterministically, using average load shapes and load growth. The forecast growth rate averages 1.5 percent per year for the WSCC as a whole. Load growth forecasts for the individual load-resource areas are provided in Appendix A. High loads, like poor hydropower conditions may have a disproportionate effect on prices. We plan to further explore the effect of load variation on prices.

One of the most significant drivers of power prices and, as a consequence, new generation development, is the price of natural gas. Our natural gas price forecasts have been revised upward to reflect recent trends. Natural gas prices in AURORA are referenced to the price at Henry Hub, Louisiana. The Henry Hub gas price for 2000, for example, used for this study is \$2.40/MMBtu, compared to \$2.05/MMBtu for the Council's 1998 Bonneville costs and revenues study[11].

The Henry Hub base price is adjusted to account for regional differences. For example, in the past Northwest gas prices have been low relative to the rest of the West because of our access to gas from Alberta and British Columbia and the relative lack of competition for that gas. The recent extension of the Northern Border pipeline to the Chicago area has eroded that price advantage. Completion of the Alliance pipeline to Midwest markets is expected to sustain the higher prices now seen for western Canadian gas. This price increase is reflected in our current forecasts of Northwest gas prices (Figure 15). Also shown are the price forecasts for gas at Henry Hub, Montana coal and distillate fuel oil. Additional information regarding fuel prices is provided in Appendix A.

Figure 15
Selected Fuel Price Forecasts



The new resource alternatives considered in this study include simple and combined-cycle combustion turbines fired by natural gas, wind, landfill gas energy recovery, advanced coal-fired power plants and central-station solar photovoltaic plants. Natural gas combined-cycle combustion turbine power plants are currently the generating technology of choice, and are likely to comprise the majority of new baseload capacity brought into service over the period of interest in this study. Simple-cycle gas-fired combustion turbines may be the economic choice for peaking applications. There is great interest in promoting the development of generation using renewable resources, and it is likely that various renewable resource incentives such as production tax credits and green power marketing programs will continue through the period of interest. We used a production credit of 1.5 cents/kWh for new renewable resources, extending through 2010 as a proxy for various renewable resource incentives. In the longer-term, it is possible that distributed generation such as packaged small-scale cogeneration units using

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[11] Northwest Power Planning Council. Analysis of the Bonneville Power Administration Potential Future Costs and Revenues (Document 98-11). June 1998.

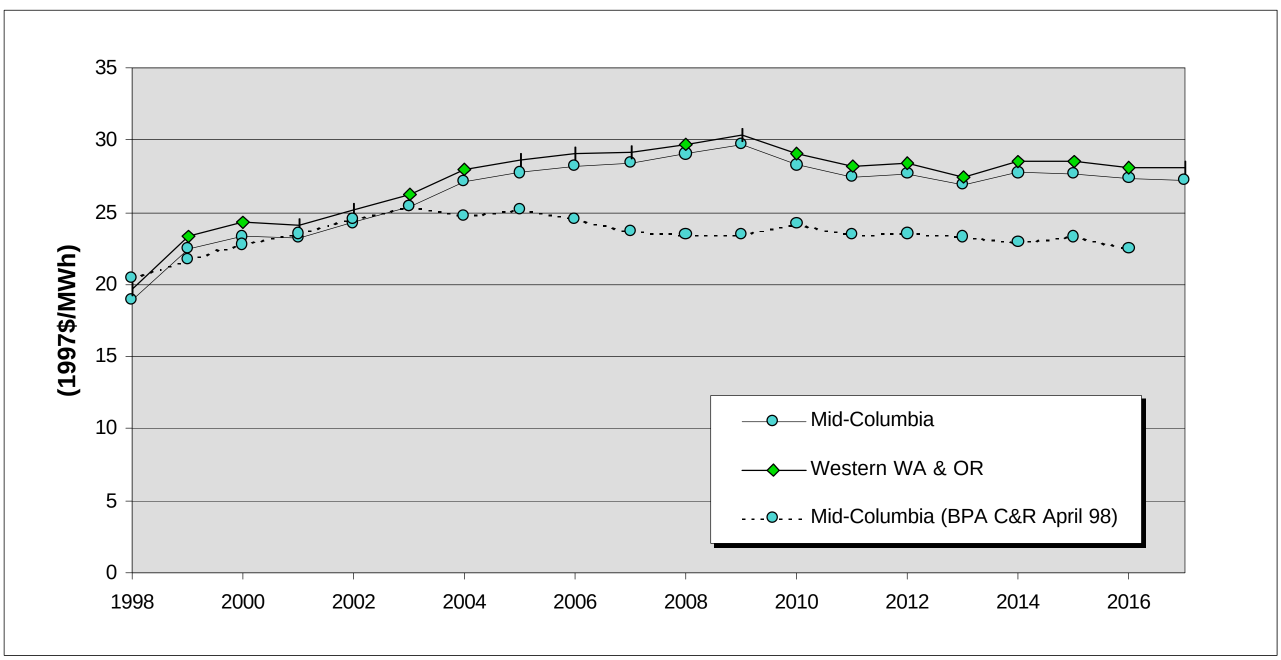
microturbine or fuel cell technologies will begin to penetrate the market. These, however, have not been specifically modeled. The new resource alternatives used in these studies are further described in Appendix A.

Finally, assume that some load could be voluntarily curtailed if economic compensation were available. When resources are insufficient to meet load, the price of this curtailed load determines the market price. Our estimates for the supply curve of unserved load rely on work done as part of the Council's 1998 study of Bonneville future costs and revenues. Based on limited information from Florida and California load curtailment programs, we assume that up to 25 percent of load is available for voluntary curtailment. For modeling purposes, this 25 percent is divided into five, 5 percent blocks. These curtailment blocks are priced at $50, $100, $150, $250 and $500 per Megawatt-hour. AURORA's system expansion results are sensitive to this parameter, and it is one subject to considerable uncertainty.

Forecast Electricity Prices

AURORA forecasts wholesale electricity prices for the 15 load-resource areas and for the major WSCC trading hubs. Prices are forecast over a 20-year period to allow the cost-effectiveness of generating resource for the 2000 - 2006 period of interest to be more accurately assessed. Forecast average annual Pacific Northwest prices are shown in Figure 16. Mid-Columbia prices are representative of eastside Pacific Northwest, whereas the Western Washington and Oregon prices are representative of westside. The Mid-Columbia forecast developed for the Council’s 1998 assessment of Bonneville's future costs and revenues is shown for comparison.

Figure 16
Forecast Annual Average Mid-Columbia Electricity Prices



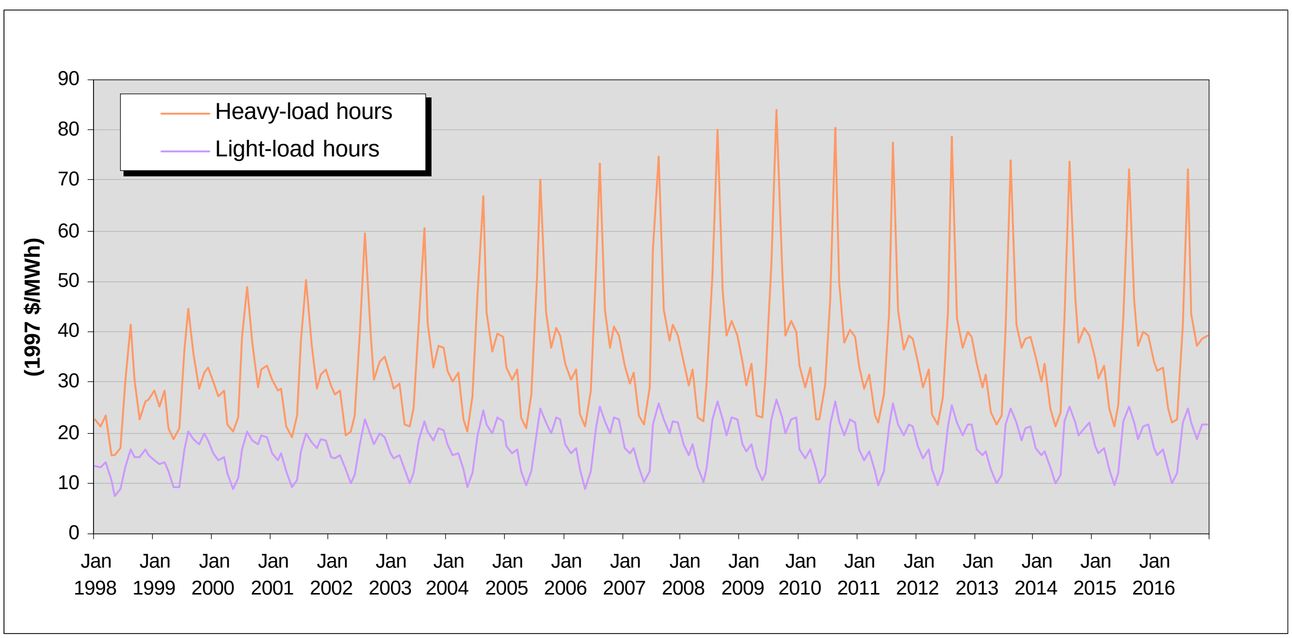
The overall form of the price forecast is very consistent between studies. Prices gradually increase through the early years of the study period as loads grow. Increasing loads force the dispatch of more costly, less efficient units to meet peak period loads. As prices approach the fully allocated cost of new generating resources (primarily gas-fired combined-cycle units), new units are added. Average prices level off at the fully allocated cost of these new resources. Because forecast increases in the efficiency and reduction in cost of new plants largely offset forecast increases in gas prices, prices remain fairly stable in real terms once reaching the fully allocated cost of new plants. Further real price increases would not be expected unless gas price escalation exceeded the offsetting effects of efficiency improvements and capital and operating cost reduction.

The West Side area forecast prices exceed the Mid-Columbia prices by an average of $0.80/MWh over the study period. This results from the persistent West Side capacity deficit and the transmission losses between the West Side and exporting areas, particularly the East Side. (This study assumed no trans-Cascades wheeling or congestion charges.)

While agreeing closely with the base case forecast prepared in 1998 for the Council's assessment of future BPA costs and revenues (lower curve) during early years of the study period, the current forecast ranges up to 25 percent higher during the later years. Higher fuel price forecasts and corrected hydropower energy characteristics appear to be the principle reason for higher long-term prices. Other revisions to assumptions and the model also contribute to the difference between the electricity price forecasts.

The annual average prices of Figure 16 obscure the increasingly evident shorter-term volatility of wholesale power prices. Figure 17 shows monthly average prices for heavy and light load hours. While off-peak prices remain relatively stable, increasingly strong peaks are forecast for late summer months. These are produced by the influence of daily air-conditioning loads in California and the Southwest. As these loads grow, increasingly less efficient and costly generating capacity (or economic curtailment) is dispatched, increasing peak period prices. While we think of the Northwest as a winter peaking system, we are part of an interconnected western market and market prices in this region reflect that fact.

Figure 17
Mid-Columbia Heavy and Light Load Hour Monthly Average Prices



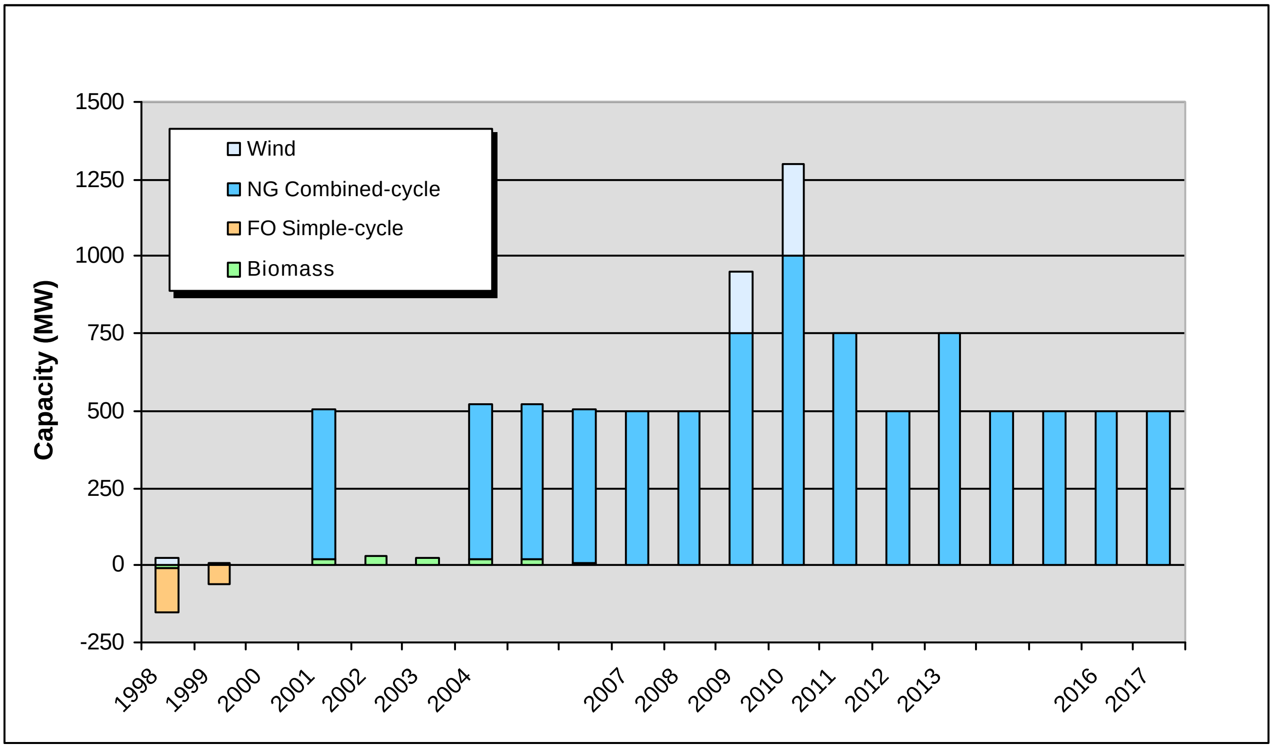
As loads grow and prices increase, wholesale prices will reach a point where the development of new generating capacity becomes economic. This point will be when future prices are sufficient to recover the fully allocated costs of constructing and operating new capacity.

AURORA forecasts net addition of about 9,000 megawatts of capacity for the four Pacific Northwest load-resource areas from 1998 through 2017. These additions are shown by resource type in Figure 18. Several older oil-fired gas turbines and a biomass unit are retired in early years (these retirements have occurred). Early-year additions include the Vansycle wind project in 1998, the Klickitat landfill gas-to-energy facility in 1999 and the 484 megawatts Klamath Falls combined-cycle project in 2001. These units are "forced" into the model as they are already completed or under construction. The recently completed Wyoming Wind Project, though owned by utilities operating in the Pacific Northwest, is not shown on this chart because it is physically located outside the Northwest.

All other additions are market-driven. Gas-fired combined-cycle units dominate new resource development. Beginning in 2004, gas-fired combined-cycle units are forecast to be added at the rate of 500 to 1,000 megawatts per year. In addition, the renewable production credit (as a proxy for an array of renewables incentives) results in the development of a moderate amount of renewables. Small-scale biomass units are added through 2006. At that time the estimated inventory of this resource is exhausted. Small blocks of wind turbines are added in 2009 and 2010, after which the assumed renewable production incentive expires. (The energy contribution of the new wind capacity is somewhat less significant than suggested by the capacity figures of Figure 18. Wind turbines typically operate at about a 30- to 35-percent capacity factor, compared to the 90- to 95-percent capacity factor of a gas-fired combined-cycle plant).

The important finding is that in none of the base studies did market-driven development of large amounts of new capacity in the Pacific Northwest occur prior to 2004, despite continuing load growth and substantial capacity deficit west of the Cascades. This reflects the transition from regulated resource development driven by very conservative (critical period) hydro criteria, to the market-driven resource development simulated in this study. Poor water conditions occur too infrequently to motivate the level of market-driven development needed to maintain previous reliability standards.

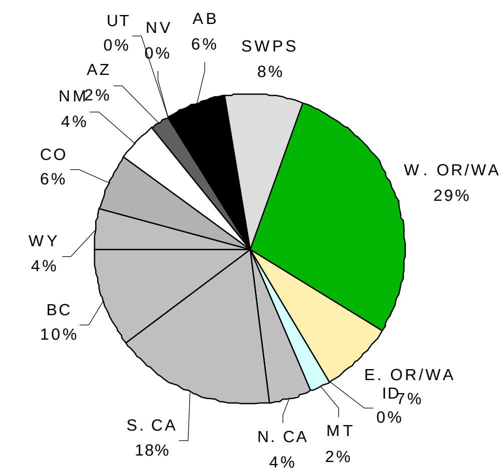
Figure 18
Pacific Northwest Market Driven Resource Development



Most of the forecast resource additions shown in Figure 18 occur in the Western Washington and Oregon load resource area (Figure 19). The western Washington and Oregon area is currently severely resource-deficit, has much larger loads than other Northwest areas and is likely to experience continuing load growth. Other factors favoring west side resource development include reasonable transmission access to seasonally complementary southwestern loads and relatively lower gas prices than southwestern areas.[12]

[12] The model treats the western Oregon/Washington area as a single area and does not incorporate any transmission constrains within that area. In reality, there are transmission constraints that could restrict transmission to the Southwest for resources located in the northern part of the western Oregon/Washington area.

Figure 19
Forecast Resource Development by Load-resource Area



Sensitivity Analyses

In forecasting future resource development we have tried to capture the issues that a project developer would most likely consider in assessing future market conditions. In addition to the factors described above, other less certain factors may influence future wholesale prices and hence a developer's decision to proceed with a project. Among these factors are the effects of a prolonged wet climate period in the Pacific Northwest and possible carbon dioxide mitigation policies. The effect of possible removal of federal dams to support fisheries restoration efforts will be analyzed in Phase 2 of the study.

Pacific Decadal Oscillation

There is evidence that a shift to a cool-wet climatic regime occurred in the late 1990's. If so, we can expect generally cooler and wetter conditions in the Northwest for the next 20 to 30 years. The resulting augmentation of hydropower production would tend to depress wholesale electricity prices and further defer the time by which new capacity additions would be economic.

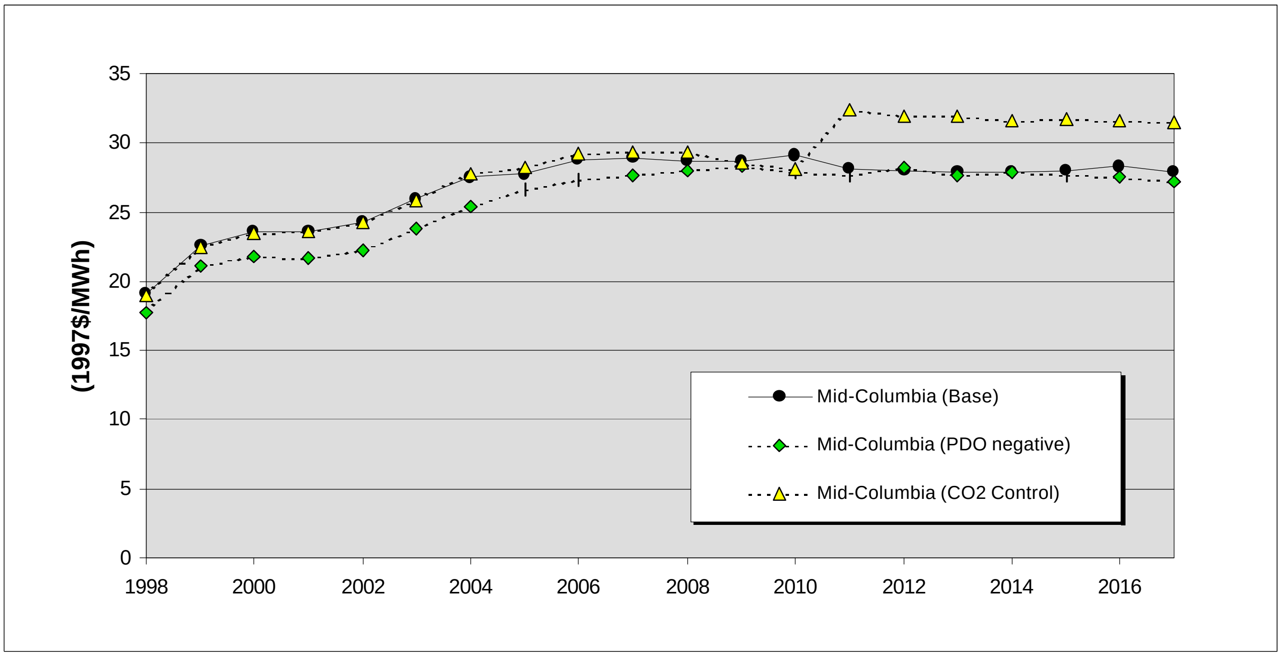
Two main patterns of climatic variation that significantly affect the Pacific Northwest are the El Nino Southern Oscillation (ENSO) and the Pacific Decadal Oscillation (PDO)[13]. ENSO, which recurs irregularly on a two- to seven-year time scale, produces warm, dry (El Nino) conditions or cold, wet (La Nina) conditions. PDO, likewise, can produce warm, dry conditions (PDO positive) or cool, wet conditions (PDO negative). The PDO regimes appear to persist for 20 to 30 years and appear to shift abruptly. PDO and ENSO effects are additive, so warm, dry years, for example, can occur during a cool, wet PDO cycle. Nonetheless, the predominant weather during a PDO phase will be that characteristic of the current phase.

The effect of a cool, wet PDO phase on power prices and capacity additions was simulated by substituting average 1946 through 1976 water conditions for the average water conditions of the base case. The years 1946 through 1976 constitute a cool, wet PDO regime for which complete water records

[13] Additional information concerning Pacific Northwest climate variability can be obtained from the Pacific Northwest Climate Impacts Group at the University of Washington. The group's website is http://tao.atmos.washington.edu/PNWimpacts/main.html.

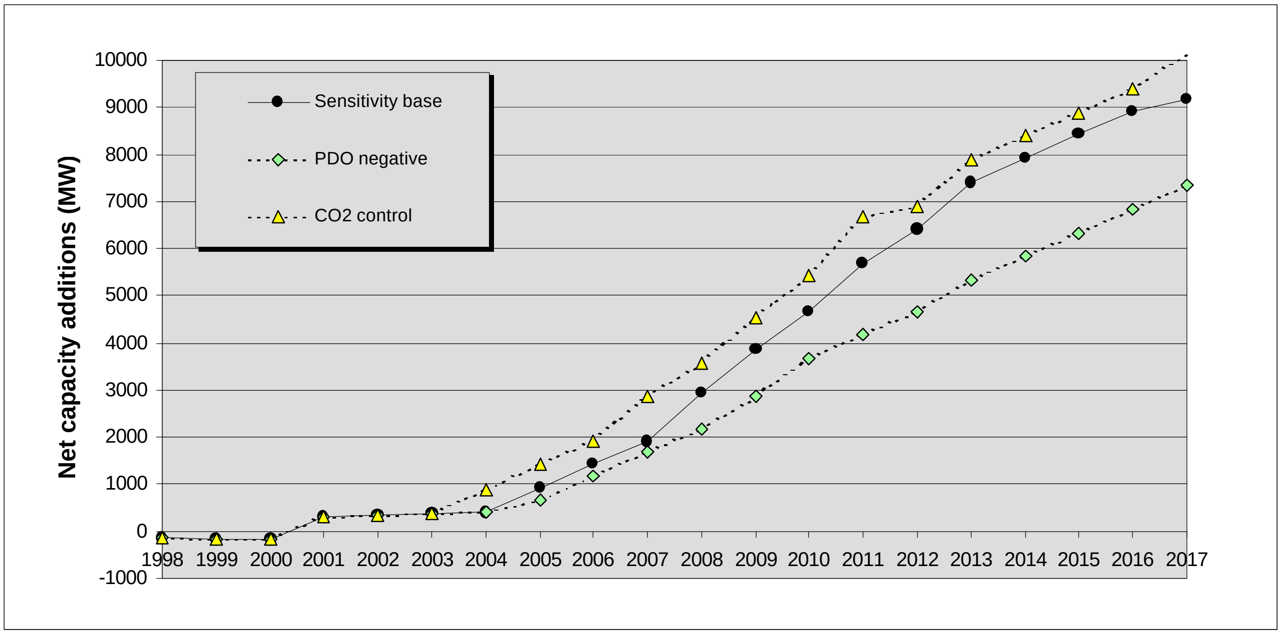
are available. As expected, cool-wet PDO conditions depress prices. As shown in Figure 20, Mid-Columbia prices average 4 percent lower than in the base case (The base case of this and the following sensitivity analyses differs slightly from the principal case described above. The relative effects of the sensitivity analyses should be consistent). The price effects of the cool-wet PDO are most pronounced in the earlier years of the study period when the additional hydro energy curtails dispatch of more expensive peaking units, depressing prices. This effect largely disappears following 2011, once prices have leveled at the fully allocated cost of new resources.

Figure 20
Effects of Sensitivity Analyses on Mid-Columbia Prices



As expected, cool-wet conditions retard the time for which market-driven resource development becomes economic. Initial-year service of market-driven new combined-cycle plants is one unit (250 megawatts) rather than two (500 megawatts). Moreover, as shown in Figure 21, the subsequent rate of development is slower than under base conditions. Clearly, consideration by developers of the possible effects of a prolonged cool-wet climate phase would reduce the rate of market-driven resource development below the rate described earlier. However, if better water conditions actually occur, the probability of failing to meet load would not necessarily increase. The effects of a cold-wet PDO phase on system reliability depend upon the probability of periodic El Nino-driven poor water conditions during the generally wet climate phase.

Figure 21
Effects of Sensitivity Analyses on Pacific Northwest net Resource Additions



Carbon Dioxide Mitigation

Increasing evidence of global climate change from human activity[14] may lead to incentives to reduce carbon dioxide production from fossil fuel combustion. A developer may consider the possible effect of future mandatory carbon dioxide control measures when assessing the financial viability of proposed generating capacity. The possibility of such measures cannot be discounted. Oregon currently requires developers to offset a portion of their carbon-dioxide production, and such efforts are likely to spread if the evidence of human-induced climate change continues to mount.

The effects of carbon-control measures on new resource development are not intuitively obvious. On one hand, generation of power from any fossil-fired plant, including gas-fired combined-cycle units, would become more expensive. This might suppress development of new fossil-fueled generating capacity and reduce energy demand through price elasticity. On the other hand, because of the relatively low carbon content of natural gas compared to other fossil fuels, and the high thermal efficiency of combined-cycle plants, replacement of existing coal or oil-fired units with new combined-cycle units may become economic.

Possible future carbon control measures were simulated by a fuel carbon tax of $10/ton carbon dioxide equivalent. The tax is assumed to take effect in 2011, following expiration of the renewables production incentive. As expected, wholesale prices increase abruptly by about $4.00/MWh (about 14-percent) with introduction of the tax in 2011 (Figure 20). Also, prices are higher, by roughly $0.5/MWh from 2005 through 2008, possibly from accelerated development of higher-cost, low-CO2 resources during this period.

[14] Wigley, Tom M. L. The Science of Climate Change: Global and U.S. Perspectives. Pew Center on Global Climate Change. June 1999. Also see www.pewclimate.org.

In the Pacific Northwest, the earliest market-driven development of new combined-cycle plants shifts forward by about a year (Figure 21). Combined-cycle plant development continues on the West Side at the maximum rate allowed in these studies (500 megawatts per year) through the study period. Wind development in the Northwest increases from 500 to 1,000 megawatts, but still ceases when the renewables production incentive transitions to a carbon tax in 2011 (wind development continues in areas with more favorable wind regimes).

Because of the uncertainties associated with future carbon dioxide regulation, it seems unlikely that developers would advance development schedules on the anticipation of later enhanced returns on a project. However, these results suggest that the effects of possible future carbon control measures should not discourage developers of gas-fired combined-cycle power plants.

Conclusions

Because of construction lead-time requirements, it is unlikely significant new capacity could be placed in service in the Northwest prior to the winter of 2001-2002. Simple-cycle units, requiring about a year of construction could be in service by that time. However, none of the currently licensed Northwest sites are permitted for simple-cycle capacity. Not only has there been little apparent recent interest in the development of new simple-cycle capacity, but also several older simple-cycle units have recently been retired.

This assessment suggests that the development of new generating capacity by independent developers is unlikely to be economical prior to about 2004. Following that time, it appears that the wholesale market will support relatively constant development of new capacity in the region at the rate of 500 to 1000 megawatts per year. This capacity would be predominantly gas-fired combined-cycle units, preferentially located west of the Cascade Range. Under the assumption that development incentives for renewables continue for the next decade, we could also see development of land-fill gas energy recovery, several hundred megawatts of wind capacity and possibly other types of relatively low-cost renewables.

Though these findings are very consistent throughout model runs performed for this assessment, it would not be unrealistic to expect one or two new combined-cycle projects (beyond the Klamath Cogeneration Project) prior to 2004. Because of the large number of assumptions required for this forecast and the complexity of the modeling process, we are less certain of this forecast than we are of other elements of this study. The wholesale price forecasts, and in turn, the forecasts of market-driven resource development, are particularly sensitive to assumptions regarding load curtailment and fuel prices. The cost and availability of voluntary load curtailment is poorly understood, and fuel price forecasts are inherently uncertain.

On one hand, our estimates of new generation costs may be pessimistic. Developers may be able to secure better deals on fuel, equipment or financing than assumed here, allowing them to proceed with development earlier than forecast. Some developers may have sufficient financial resources to carry them through early years of low market prices in anticipation of higher payoffs in the longer term. Moreover, new project development is likely to be cyclical, with periods of optimistic development followed by periods of surplus. A development cycle could be stimulated by a cyclic upswing in market prices. These factors are not easily captured in Aurora, a model that seeks perfect economic timing of new projects.

Other factors weigh against earlier development than forecast here. Project development opportunities abound in North America. Over two hundred simple- and combined-cycle projects have been announced in North America within the past two years. Many of these projects are located in regions having more predictable prices than the Pacific Northwest. Most project developers are national or international businesses and will generally direct their investments to the projects with the most certain returns, other factors being equal. This same abundance of proposed projects has shifted the “heavy duty” turbine business from a buyer's to a seller's market. Delivery times for new equipment orders are reported to be three years. Though a large-scale developer might shift a couple of advanced-order turbines to a Northwest project, delivery constraints may limit the availability of many new heavy-duty machines prior to 2004. The aeroderivative turbine market remains weak due to slow aircraft orders, however these units are not well suited for combined-cycle applications.

A final point is that AURORA is a less-than-perfect tool for this kind of analysis. It essentially tells us what, when and where a "rational actor" developer would build to serve base loads. Not surprisingly, AURORA primarily chooses to develop combined cycle units whose relatively high thermal efficiency and resulting low operating costs will allow them to operate a relatively large percentage of the time. The kind of problem we are trying to address is a situation of potentially significant but relatively short and infrequent periods of supply inadequacy during which wholesale prices could be expected to be quite high. For such a situation, a generating resource with lower capital costs and higher operating costs such as a simple cycle combustion turbine might make more sense.

To evaluate such a situation, a model needs to be able to capture the variation in hydro generation and loads. Optimally, this would be done using stochastic modeling of hydropower conditions. AURORA does have the capability to be run in a Monte Carlo mode with variations in hydro corresponding to the 50-year historical record. However, for a resource expansion analysis, the run time is prohibitive. We are trying to simulate the price effect of year-to-year hydro variability by using somewhat drier than average water conditions approximating the condition that would yield expected prices over the long term. Aurora's stochastic modeling capabilities can, however, be used relatively efficiently to evaluate the economics of a specified resource schedule. Staff is working on an analysis where single-cycle units are substituted for some of the combined cycle units and their starting dates are moved up in time to see if the market would support such development. We are, however, unaware of any developers in the Northwest who are actively considering the development of single cycle units.

In conclusion, although there are shortcomings to our analysis, as a practical matter, it would be very difficult to bring 3,000 megawatts of new generation on-line in the Northwest by 2003. Though a new project or two may see service in the Northwest by 2003, it is highly unlikely that the market will deliver the 2,500 to 3,000 megawatts of new capacity required to resolve the reliability issue by 2003.

Operation of the Hydroelectric System and Impacts to Fish and Wildlife

During times when all available resources are generating electricity and available imports are being used and the region is still unable to meet its demand, the hydroelectric system can be pushed a little harder, over short periods of time, to help out. This is often called using hydro flexibility for emergency conditions. The term “hydro flexibility” refers to the additional energy that can be generated when some operating constraints of the hydro system are temporarily violated. Any additional water used would be replaced as soon as possible through additional power imports or thermal generation at a later date so as to be able to meet critical fish recovery standards for reservoir levels and flows. The use of such flexibility for winter cold snap reliability is acknowledged in the current Biological Opinion on Hydropower Operations.

Some level of use of flexibility is inevitable. We have treated the use of hydro flexibility as a last resort, after additional imports, use of non-treaty hydro storage and provisional drafting of Canadian reservoirs. Over the next couple of years, before new resources or voluntary load reduction can be added to the system, it could be necessary to use hydro flexibility quite heavily to avoid involuntary curtailment.

The preliminary results of this reliability study, with regard to the operation of the hydroelectric system and fish and wildlife concerns, can be summarized as follows:

Practically speaking, it will not be possible to add any significant amount of new generating capacity in the Northwest for at least a few years. Beyond that period, it is not clear that the market will result in sufficient development to assure adequate supplies. This means that over the next few years, there is a higher probability that reservoirs will be drafted to lower elevations during the winter months to maintain service to customers. In years when this occurs, less water will be available for spring and summer flow augmentation to aid anadromous fish migration. In the near term, the effect on flows is not that great. In the longer term, without new resources, the result could be significant.

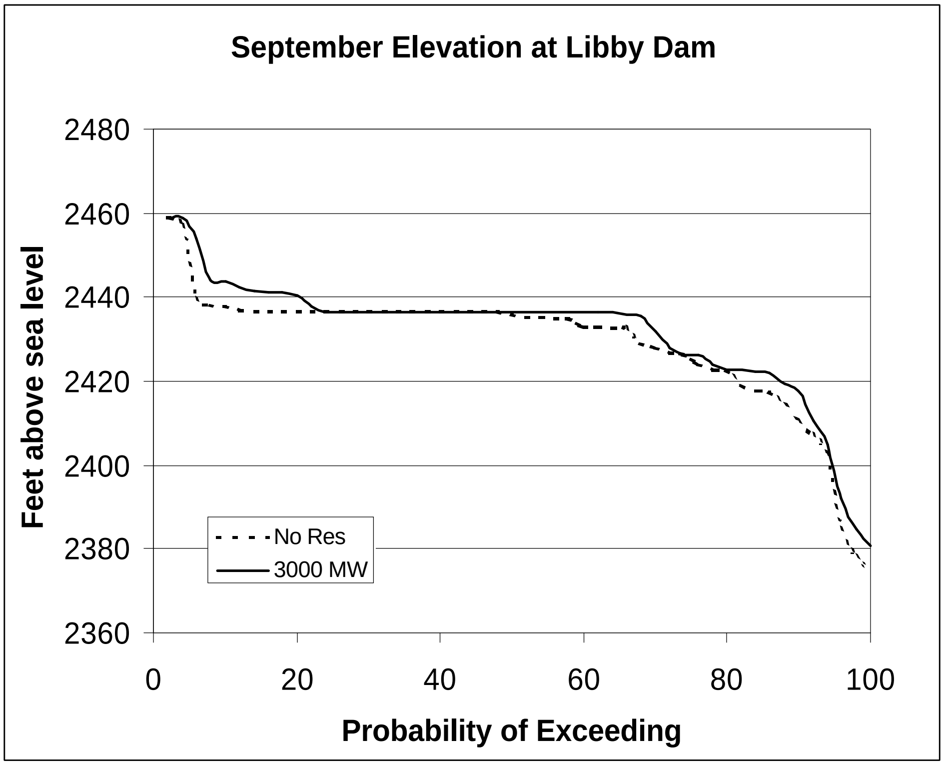
To illustrate the effects of using hydro flexibility we examined two cases. In each case hydro flexibility is used when needed. In the first case, no new resources come online until after 2003. In the second case, 3,000 megawatts of new generating capacity is on-line by 2003. We chose to observe impacts at Libby Dam in 2003 simply as an example of how all the major reservoirs will be affected. While impacts will vary by reservoir, the results at Libby are a fair representation of what would occur at other projects.

The next six figures display what are commonly called “duration” curves. These types of graphs indicate the likelihood that some parameter will be at or above a certain level. In Figure 22, below, for example, the curves show the likelihood of Libby Dam’s reservoir being at or above a certain elevation in September of 2003.

Libby’s elevation duration curve for each of the two cases mentioned earlier is shown in the figure below. The first curve (dashed line) represents the scenario with no new resource development in the Northwest. The second case (solid line) is a scenario in which 3,000 megawatts of newly installed generating resources are online by 2003.

As an example of how to read the chart, examine the solid line. As you follow its descent from an elevation of 2,460 feet on the left to about 2,380 on the right, you will notice that it drops away from the 2,460 level at about the 4-percent mark on the horizontal axis. This means that there is a 4-percent probability that Libby’s reservoir will be at 2,460 feet (full) in September of 2003.

Figure 22

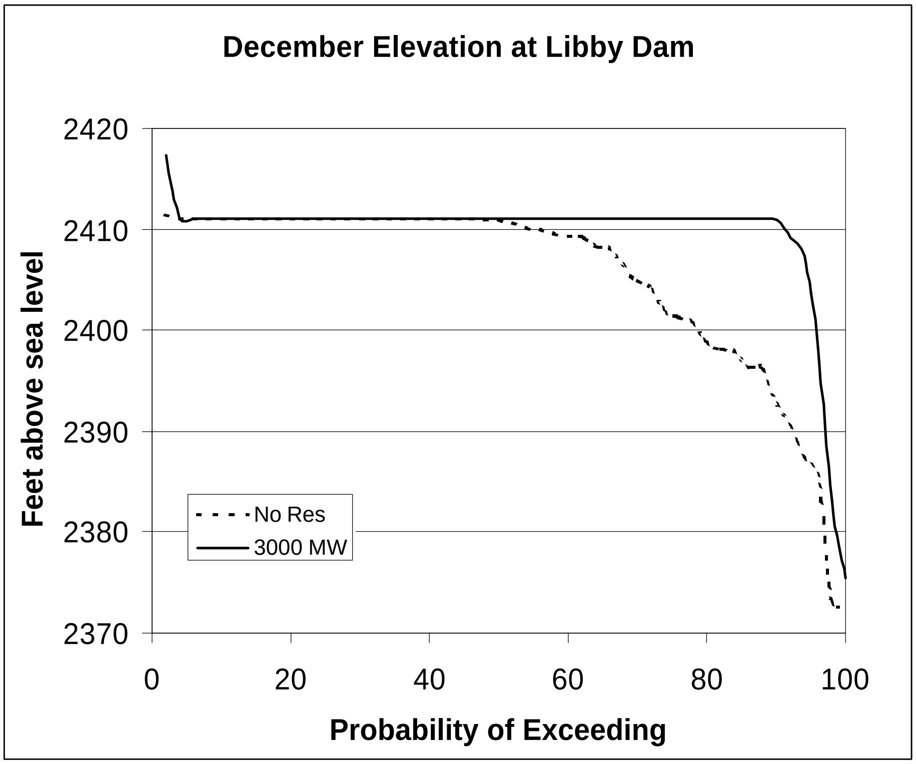


By observing the curves in Figure 22, we conclude that there is about a 70-percent chance that Libby will be at a lower elevation in September of 2003 under the "no new resource" scenario (about 70 percent of the time, the dashed line is below the solid line). In years when Libby is lower, it will be about four feet lower on average. The difference in elevation ranges from one to seven feet in all but one case (in the worst case, the difference was 14 feet).

Figure 23 presents the December elevation probability curves for Libby in 2003. Although the scale in this figure is different from the one in the previous chart, it should be obvious that the impacts of not including new resources are more severe than in September. This is true because demand for electricity in the Northwest normally peaks sometime between December and February and, if hydro flexibility is going to be used, it will more likely be used in these months.

It is about 50 percent more likely under the "no new resource" scenario that Libby will be lower in December. In years when Libby is lower, it will be about eight feet lower on average. In the worst case, it could be as much as 20 feet lower. The Corps of Engineers would like Libby's reservoir to be no lower (and no higher) than 2,411 feet by the end of December. With new resources in place, that occurs over 90 percent of the time. Without new resources, about 50 percent of the time Libby's elevation will be below that level. Not having Libby at 2,411 feet by the end of December reduces the likelihood that it will reach its desired elevation for anadromous fish considerations by mid-April.

Figure 23



The more severe drafts in winter months under the "no new resource" scenario can often be made up by mid-April when the salmon migration typically begins. (Water is restored by reducing flows and importing energy from out of region or from in-region non-hydro resources).

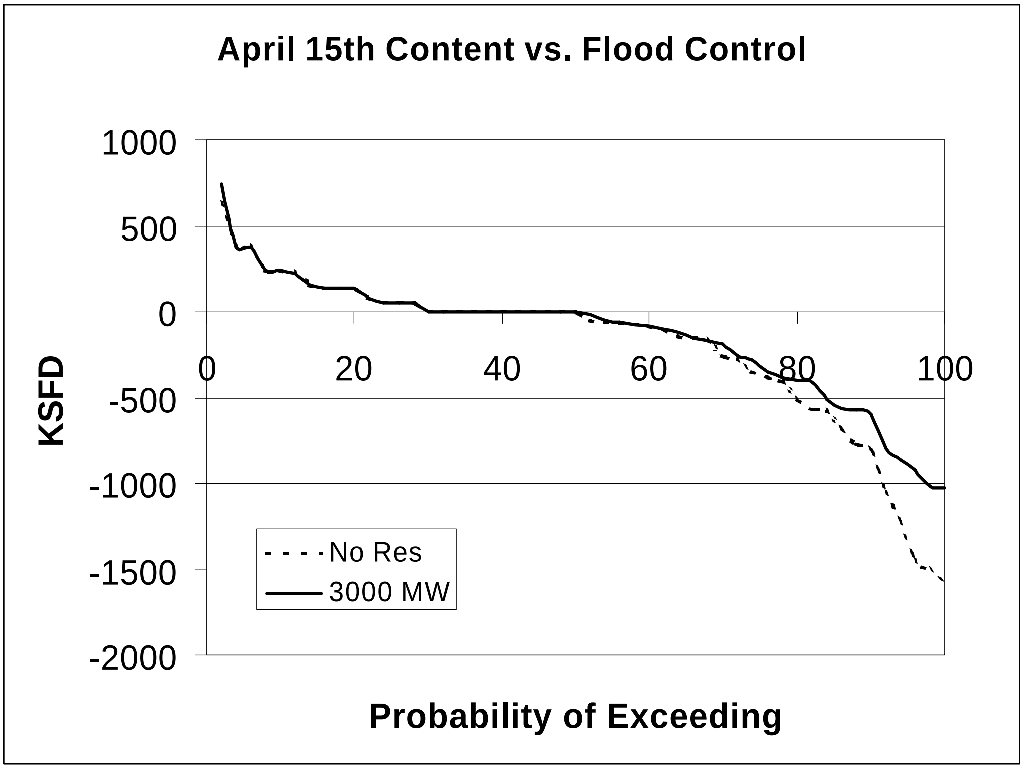
Figure 24 below is also a probability chart, but unlike the previous charts it presents the likelihood that Libby will be "as full as possible" by mid-April. The curves in this figure indicate how much volume of water (vertical axis is volume in units of thousand second-foot days, or KSFD) above or below flood control is likely to be in the Libby reservoir on April 15th in 2003. When Libby's elevation is exactly at the flood control level, the curve will be at zero.

Flood control elevation is normally the highest elevation that a reservoir can be operated to. In wet years, the flood control elevation tends to be lower. This is intended to provide a space for the expected snowmelt runoff and protect against flooding.

In Libby's case, the reservoir elevation can sometimes be higher than flood control due to an agreement with Canada regarding the elevation at Kootenay Lake (which is downstream from Libby). This effect can be seen on the left-hand side of the graph where the curves are above zero. About 30 percent of the time, Libby will be above its flood control elevation by mid-April.

About 44 percent of the time, Libby will have less volume in its reservoir under the "no new resource" scenario. On average, the shortage will be about 300,000 acre-feet. In the worst case, the shortage is about one million acre-feet.

Figure 24

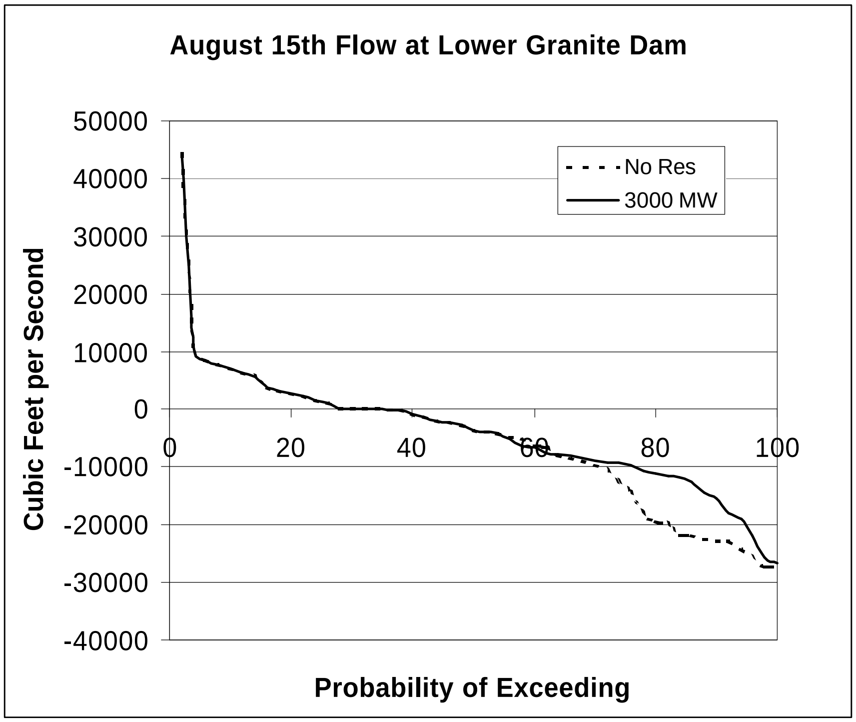


River flows are important for anadromous fish migration. The migration period usually runs from mid-April through August. The average runoff volume during that time period is about 92 million acre-feet. U.S. reservoirs can store about 20 million acre-feet. Under the National Marine Fisheries Service's current Biological Opinion, about 12 million acre-feet can be used to augment flows.

About half the time under the "no new resource" scenario, U.S. reservoirs will have less water by mid-April. In these cases, the average shortage is about 1.1 million acre-feet or about 10 percent of the controllable volume for flow augmentation. Typically, the shortfalls will occur in dry years when the runoff volume is low.

The impacts of this shortage appear in Figure 25 below, which shows the flow probability (relative to the target flow) at Lower Granite Dam in the first half of August in 2003. (We chose to show this month because, typically, the volume of controllable water is not used up until late July or August. Thus differences in flows between the two scenarios we are examining will most often appear in this time period.) Under each scenario there is about a 30-percent probability that August flows at Lower Granite will be equal to or greater than the target level. (The target flow at Lower Granite in this month is 50,000 cubic feet per second). About 40 percent of the time, flows are lower at Lower Granite Dam under the "no new resource" scenario. In years when flows are lower (typically drier years), they average about 4,500 cubic feet per second lower. During these years, the flow at Lower Granite averages between 30,000 and 40,000 cubic feet per second. In the worst case, the flow is nearly 10,000 cubic feet per second lower.

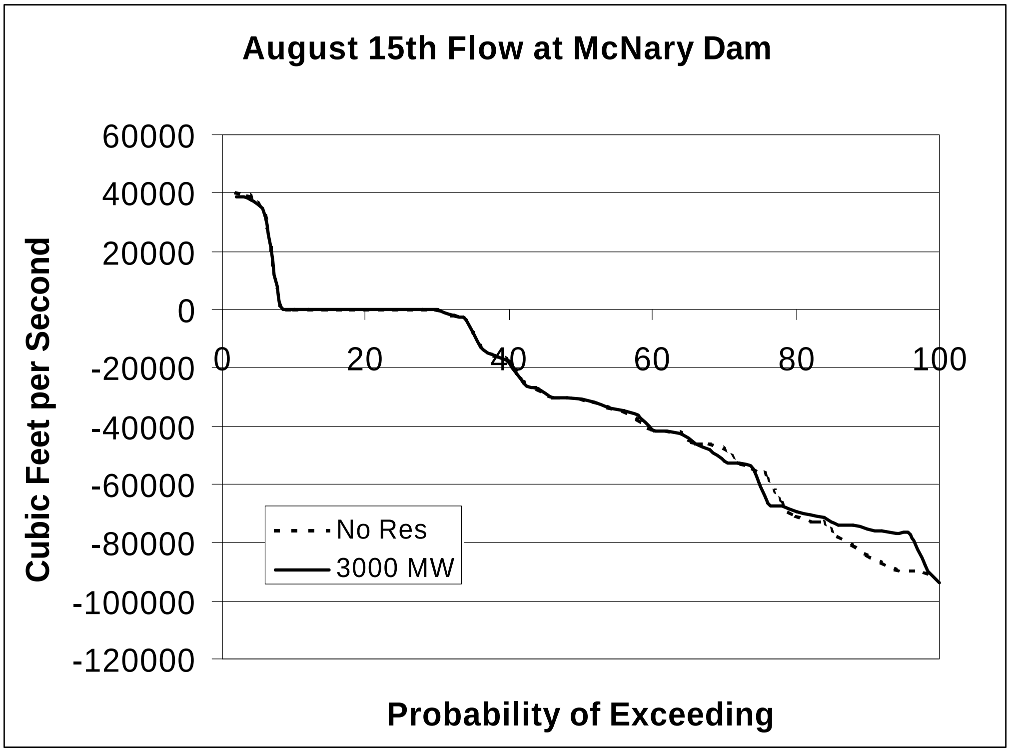
Figure 25



In looking at the flow probability curves at McNary Dam, in Figure 26 below, we observe the impacts of actions on both the Snake and Columbia rivers. Again we see that about 30 percent of the time, under each scenario, flows at McNary are equal to or greater than the target level. (The Biological Opinion flow target at McNary for this period is 200,000 cubic feet per second).

About 22 percent of the time (the dashed line is below the solid line about 22 percent of the time), flows are likely to be lower in the “no new resource” scenario at McNary in the first half of August, 2003. In years when flows are lower (again, typically dry years), they average about 6,000 cubic feet per second lower. In the worst case, the flow is nearly 13,000 cubic feet per second lower.

Figure 26



Although this result is not good for migrating salmon, it is not as bad as it could be. Converting the 6,000 cubic feet per second average shortfall into units of volume yields about 200,000 acre-feet. This volume is much less than the average shortfall of flow augmentation water in April, which was about 1.1 million acre-feet. So where did the extra water come from? The answer is from reservoirs drafting below the Biological Opinion flow augmentation limits to meet power needs. Figure 27 helps illustrate what is going on.

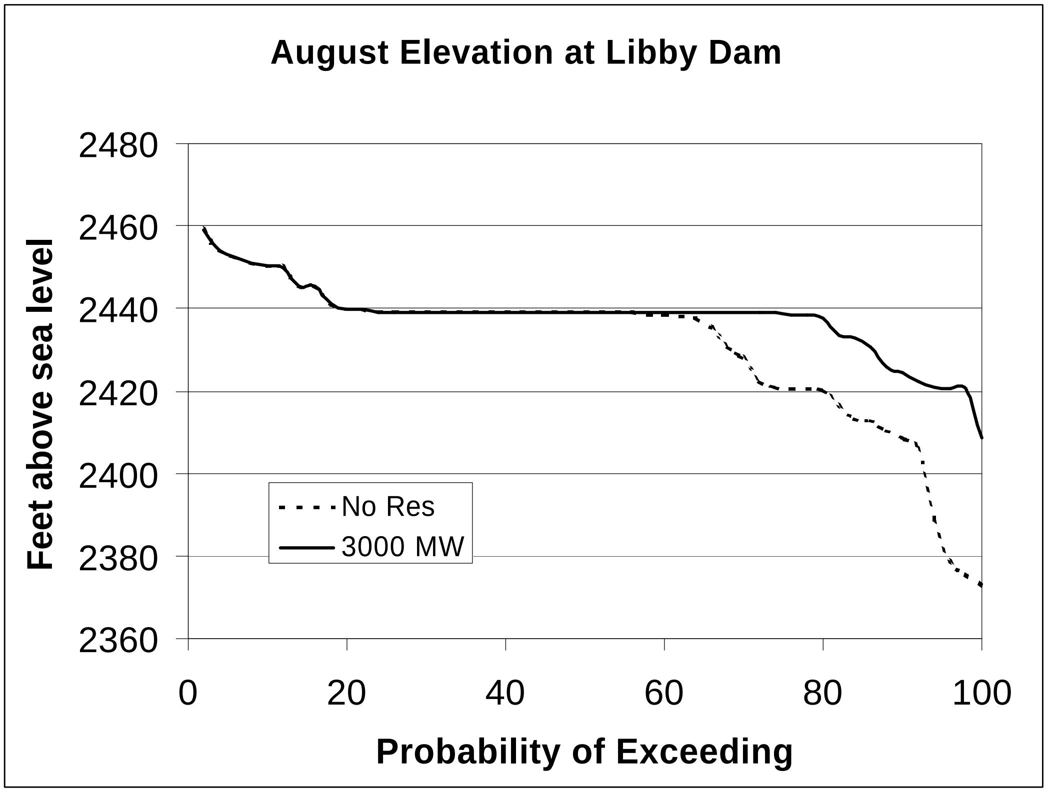
This chart (similar to the first two) shows the elevation probability at Libby Dam for the end of August in 2003. About 44 percent of the time, Libby will be lower in the "no new resource" scenario. In years when it is lower, it will be 17 feet lower on average. In the worst case, Libby is 45 feet lower.

The Biological Opinion draft limit for flow augmentation for anadromous fish at Libby is 2,440 feet (or 20 feet down from full). As can be seen in the chart below, the solid line is on or above 2,440 feet about 80 percent of the time. The remaining 20 percent of the time, Libby is drafted below this limit to help maintain flows for sturgeon or for power needs.

In the "no new resource" scenario (dashed line), Libby is below the Biological Opinion draft limit nearly 40 percent of the time, twice as often as in the "new resource" case. It is safe to assume that every time the dashed line is below the solid line, that Libby was used for power needs and not for flow augmentation. And, whenever Libby is drafted for power needs, it is coincidentally increasing river flows, which help migrating salmon. This effect tends to mitigate the shortfall of flow augmentation water (Figure 24) under the "no new resource" scenario.

Impacts to other federal reservoirs will vary but in general are similar to those for Libby. By not developing new resources and, therefore, relying heavily on the hydro system to maintain reliability results in what many would interpret to be unacceptable operations at federal hydro projects. The impacts show a higher probability that reservoirs will be at lower-than-desired elevations in the winter months and that less volume of flow augmentation water will be available by mid-April. Flows are not affected as much as one might think because reservoirs are likely to be drafted deeper than the Biological Opinion limits in the summer for power needs. In the longer run, if sufficient new generation and voluntary economic load reduction is added to the system, the use of hydro flexibility should be modest, although there will always be some level of reliance on it. However, failure to address resource needs would, over time, force greater and greater reliance on flexibility with possibly unacceptable results for fish recovery.

Figure 27



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