Regional Power Supply Adequacy/Reliability Study

Phase I Report

Northwest Power Planning Council

December 8, 1999

Background

- Study initiated at request of Bonneville Administrator Johansen
  - Growth, lack of new resource development in recent years, implications for adequacy of power supply
- Staff has tried very hard to make sure we have accounted for major factors affecting supply adequacy
  - Do not want findings discounted because we have left out any important mitigating factors
  - Focused on realistic use of hydro system, availability of imports, new resource development

The origin of this study is a presentation that Bonneville Administrator Judy Johansen made to the Council late in 1998. She expressed concerns about the growth the Northwest has been experiencing, the relatively small amount of net resource additions in the region and the implications for the adequacy of power supply. She asked the Council to look at the issue. This study is the result.

In undertaking this study, staff has consciously tried to take a what might be called "conservative" approach — trying very hard to make sure that we have adequately accounted for the major factors affecting the potential for deficits. We did not want the results of the study to be discounted because we left out some important mitigating factors.

Consequently, we have worked hard to try to get the hydro "right" — a realistic representation of how it would actually be operated; assessing the availability of imports; and evaluating the potential for new generating resources to be brought on by "the market."

Summary of key findings

- There is a problem -- over next few years without new resources, probability of being unable to serve loads at some level during winter is 24 percent
  - New resources means some combination of new generation and/or ***reliable*** voluntary economic load reduction
- To achieve a 5 percent probability in 2003 would require almost 3000 MW new capacity

Our main conclusion probably shouldn't come as a surprise to anyone who has followed developments in the Northwest power system over the last several years and has wondered what could happen when we experience a string of dry years, an extreme cold snap and some generating units go down.

What we conclude is that there is a problem — and we've put some numbers to it. Our analysis indicates that over each of the next few years, if no additional resources are added to the system, the probability of being unable to fully serve load during the winter months (December, January, February) is relatively high, reaching 24 percent in 2003. This is the probability of any supply deficit event. It could be small and of short duration or it could be a couple thousand megawatts and last over 3 or 4 days. The analysis shows the possibility of both kinds.

The Council thinks 24 percent is unacceptable. There are any number of reliability standards in the industry and any number of interpretations of them. For purposes of discussion, we've chosen the standard one year in 20, or 5 percent. To achieve a 5 percent standard in 2003 would require almost 3000 MW of new capacity to be added to the system. That capacity could be any combination of

- New generating capacity;and
- Reliable, voluntary, economic load reduction — you have to know its there when called on; it should be the choice of consumers, not forced upon them; and it needs to make economic sense for the user and the system.

Key findings (2)

- We rely heavily on imports to meet loads and help restore system when flexibility is used
  - Takes advantage of the seasonal diversity in the West Coast power system
  - Does mean that at times we are heavily dependent on a relatively few wires
  - We have not incorporated effect of unplanned transmission outages

The analysis also shows that we need to lean heavily in imports from California and elsewhere in the West. This is both to meet loads and to help restore energy (water) to the hydro system after it has been necessary to push the hydro system beyond normal non-power constraints for reliability purposes.
This is generally a good thing. It is more economical to make use of the fact that the Southwest has excess capacity when our loads are high and vice-versa. That is why the interties were built in the first place.
But it does mean that we are heavily dependent on the interties and their reliability.
We have not incorporated the effects of unplanned outages on the transmission system in our assessment of the Northwest's ability to meet loads.

Key findings (3)

- Near term, as a last resort, may have to make significant use of flexibility in hydro system -- temporarily taking additional energy (water) out of system, replacing when possible by imports, running thermal
  - Relatively small effect on spring & summer flows but lower reservoir elevations in drier years
- Long term heavy reliance on flexibility w/o new resources would lead to unacceptable results

The Northwest hydroelectric power system is still a quite flexible and adaptable power system. We can, if necessary, temporarily push that system to help us meet supply problems. What that means is, as a last resort, drafting the system below what would ordinarily be target levels in order to avoid a load-resource imbalance. That water is replaced, when possible, by backing off the hydro system and making additional power imports and running thermal plants harder.

Under most circumstances, you can do that without significantly affecting the factors that are important to salmon recovery and resident fish populations — flows and reservoir elevations. We found a relatively small effect on flows but somewhat lower reservoir elevations in dry years. In the near term, absent alternatives, this may be something we have to live with, a fact that is recognized in the Biological Opinion.

In the longer term, relying on the flexibility of the hydro system without adding new resources would lead to unacceptable impacts.

Key findings (4)

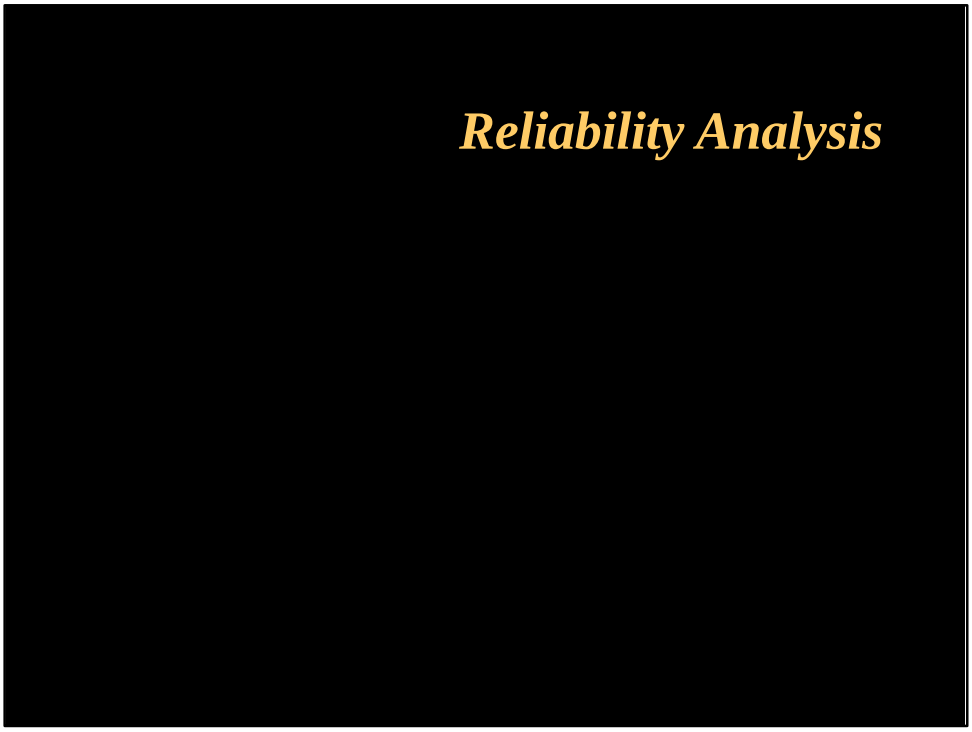
- Estimates of market-driven new generation development very difficult. With that caveat:
  - Physically could not have new generation on line before 2002 at earliest
  - Analysis suggests wholesale power market won't support sufficient new generating resources soon enough for reliability
    - May not be capturing full effects of high prices during periods of tight supply, ancillary services market
    - Might need to "subsidize" some resources to be available for reliability events - at risk of distorting the market
  - Needs further analysis

One of the more difficult aspects of this study has to do with the question of how much new generation is likely to be brought on line over the next few years in response to market forces. We are in a new world. Generation is now largely being built by independent developers. They do not have captive customers to, in a sense, absorb much of the risk of building new generation. Now developers need to be able to cover their costs and make a profit at market prices.

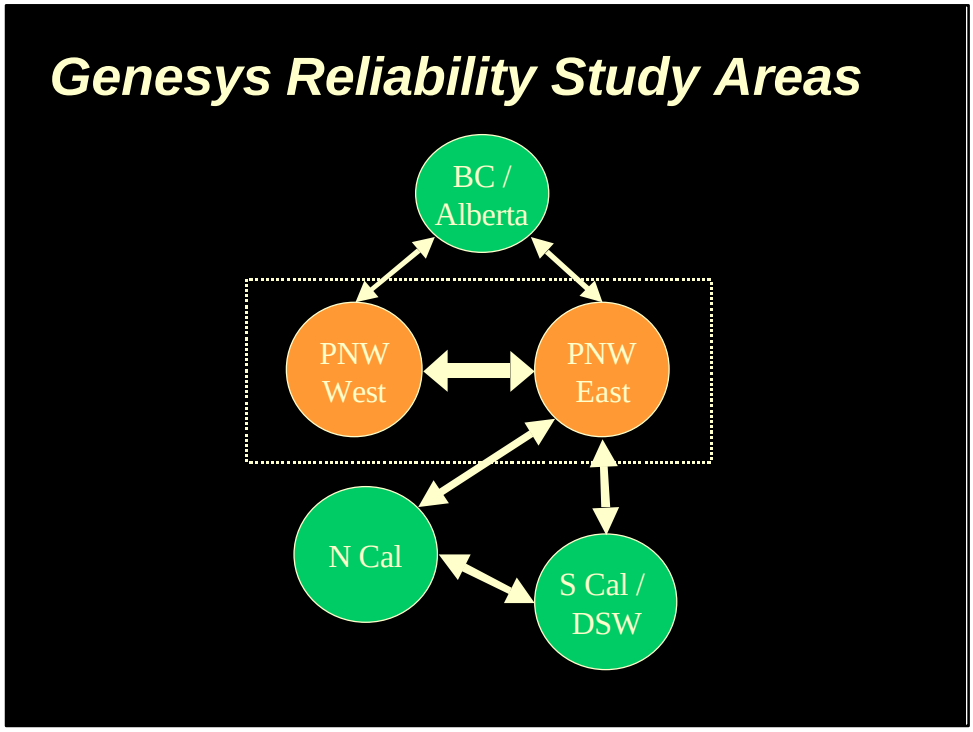
Capturing the decision process of developers is very difficult if not impossible. We have used a commercial model, Aurora, to estimate new market-driven generation. What that analysis suggests is, first of all, even if the market would support it, the lead times for plant construction are such that new generation could not come on line before 2002 at the earliest.

Beyond that, the model suggests that there will be substantial new development taking place beginning in 2004. But it is not enough nor soon enough to deal with the kind of infrequent, relatively short duration supply problems this study sees.

We are not 100 percent confident in our results. It may be that very high prices during periods of short supply could incent more development than our analysis suggests. Or the market for ancillary services may have an effect we are not capturing. There is the possibility of paying for new capacity to be built for reliability purposes, however at the risk of distorting the market. These questions need further analysis.



For this study, the Council developed a new reliability model for the Northwest, called Genesys.

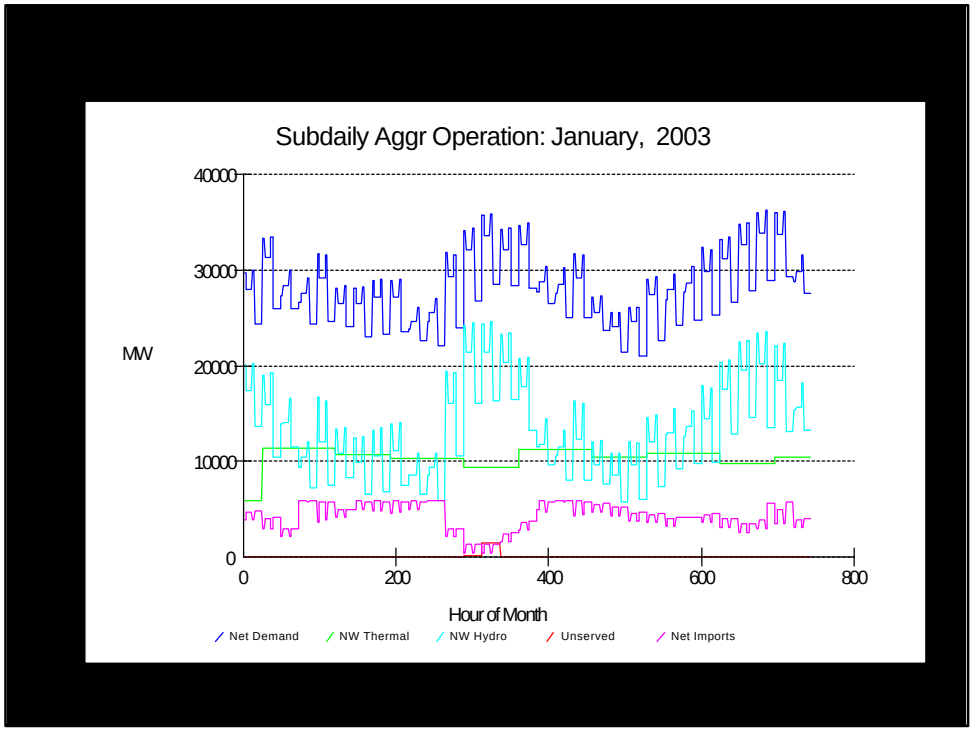


Focus area is Pacific Northwest region as defined by Northwest Power Act
PNW West/East dividing line is Cascades
PNW demand and resources modeled at high level of detail.
Less detail used for other areas.
Supply curves for available imports from non-PNW areas are based on Aurora load/resource balances, differentiated on and off peak.

Key Components of Analysis

- NW hydro uncertainty
- Weather driven demand uncertainty
- Thermal and hydro forced outage
- Use of hydro system flexibility
- Hydro instantaneous and sustained peak variation
- NW import capability dependent on weather events in the NW and Northern California
- Generation reserve requirements

Hydro generation uses the 1929 to 1978 PNW streamflow record.
Hourly demand model for PNW loads uses the daily historical NW temperature record over the same time period.
Full flexibility of hydro system is used to meet demand if required
Flex hydro, which could cause draft of reservoirs below non-power constraints (F&W targets), is used as a resource of last resort, and restored as soon as possible.
The relationship between daily average hydro energy generation and sustained peaking capability for each of 2, 4, and 10 hour duration limits is modeled. Relationships are estimated through the trapezoidal approximation linear program.
The California-Oregon Intertie (COI) south to north transfer limit is an inverse function of net PNW west side demand, per Bonneville transmission group nomogram (During severe NW cold snaps, transfer capability typically drops)
Supply availability out of Northern California is a function of daily average temperatures in Northern California due to increased native demand and gas supply constraints. Below 50 degrees, surplus for export begins to decline and reaches zero at 40 degrees. The NC daily temperature record over the same historical record is used.
Reserve requirements are tracked and are equal to the larger of 5% of hydro generation plus 7% of thermal, or the single largest contingency (frequently the intertie in cold snaps).



Genesys Northwest is a Monte Carlo simulation model which in this study was run on a daily time step over December, January, and February, with each day broken into four demand segments.
This chart shows the result of a single simulation across January, 2003 with two cold snaps in the month. It's also a poor streamflow year.
The first cold snap results in an energy shortfalls of about 100 MW for one day and 1500 MW for the following day as demand gets even higher.
Several thermal units are out across this period and availability of California imports drops because it's cold in Northern California across this same period.
Because of poor stream flows, NW storage reservoirs are lower than normal during this month, and even with use of non-treaty storage and provisional draft from Canadian projects, there is insufficient energy to meet demand in this cold snap.
No outages are observed in the second cold snap, because of warmer temperatures in Northern California and improved availability of imports.

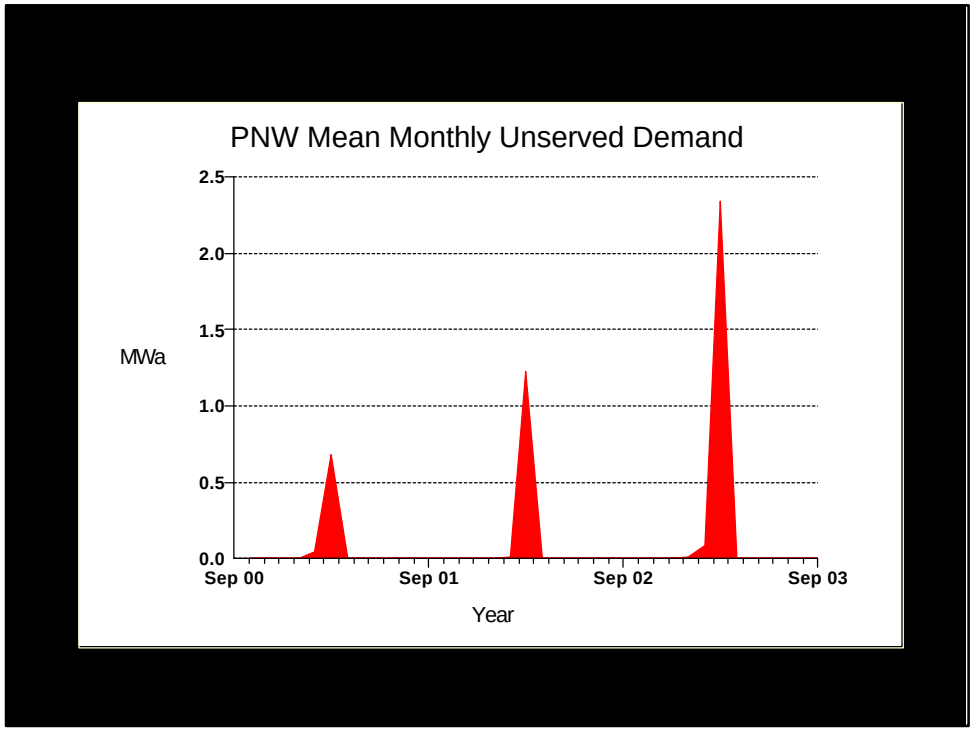
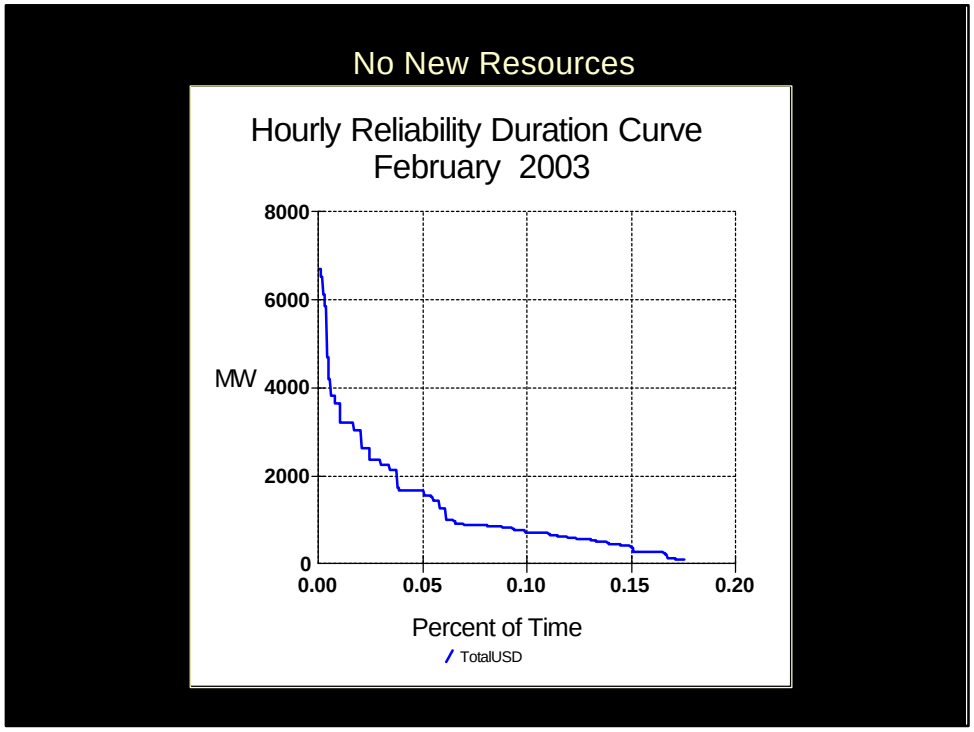
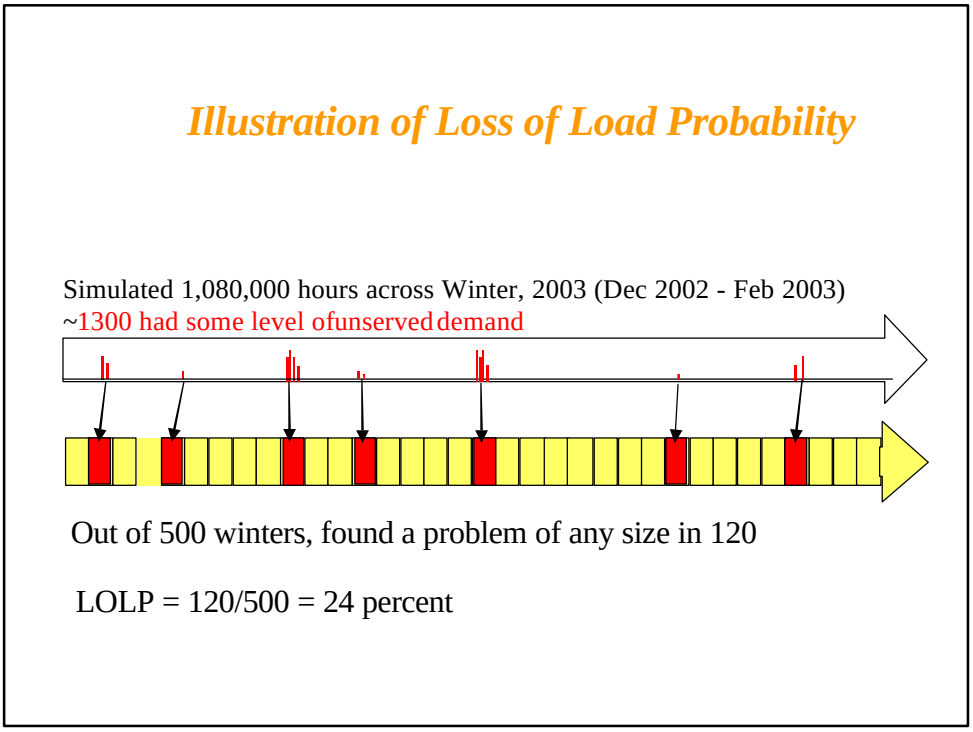


Chart shows mean result from 500 simulations, run from September 2000 through August 2003. Only the Klamath Falls cogen units (536 MW) are added to the existing NW generation system.
December, January, and February were run on a daily time step, with four demand segments per day.
Water years and temperature years were selected sequentially from the historical record and were run in lockstep mode.
The worst month for reliability is February, 2003 and shows a mean monthly unserved demand of < 2.5 average MW.
2.5 MWa appears to be small problem, but using the mean here is misleading and inappropriate.



This is a duration curve of all the reliability events found in February, 2003. The simulation examined 336,000 hours over 500 simulations.
The 2.5 MW average curtailment from the previous chart comes from this set of observations.
Only about 0.17 percent of the hours examined in February, 2003 had a reliability problem. Demand could be met in over 99.8 percent of all hours.
A small percentage of the hours with unserved demand had problems of over 4000 MW.
Most of the problems indentified were 3000 MW or less

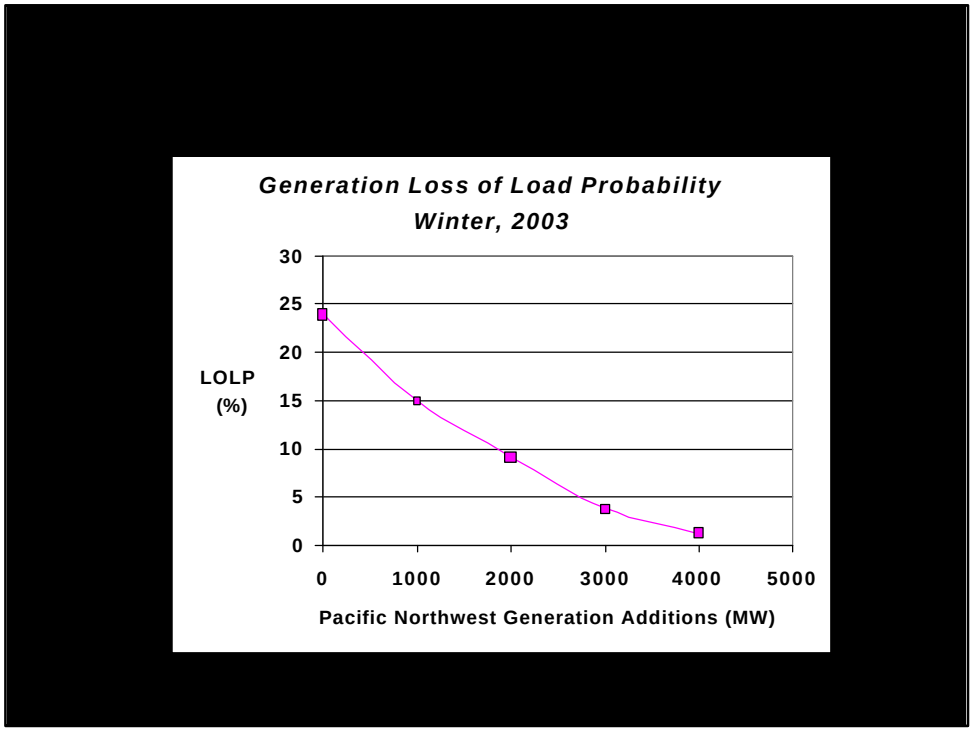


One way utilities historically have thought about generation reliability is loss of load probability. LOLP is the probability that generation will be insufficient to meet demand at some point over some specific time window.

We've defined the winter months, December to February as the time window, and in 500 simulations, examined 1,080,000 hours. About 1300 had some level of unserved demand.

Any reliability event in any hour of a winter (regardless of size or duration) causes a winter to be recorded as one in which load was lost.

Out of the 500 winters simulated, load was lost at some point in 120 of them, resulting in an LOLP for Winter, 2003 of 24 percent.



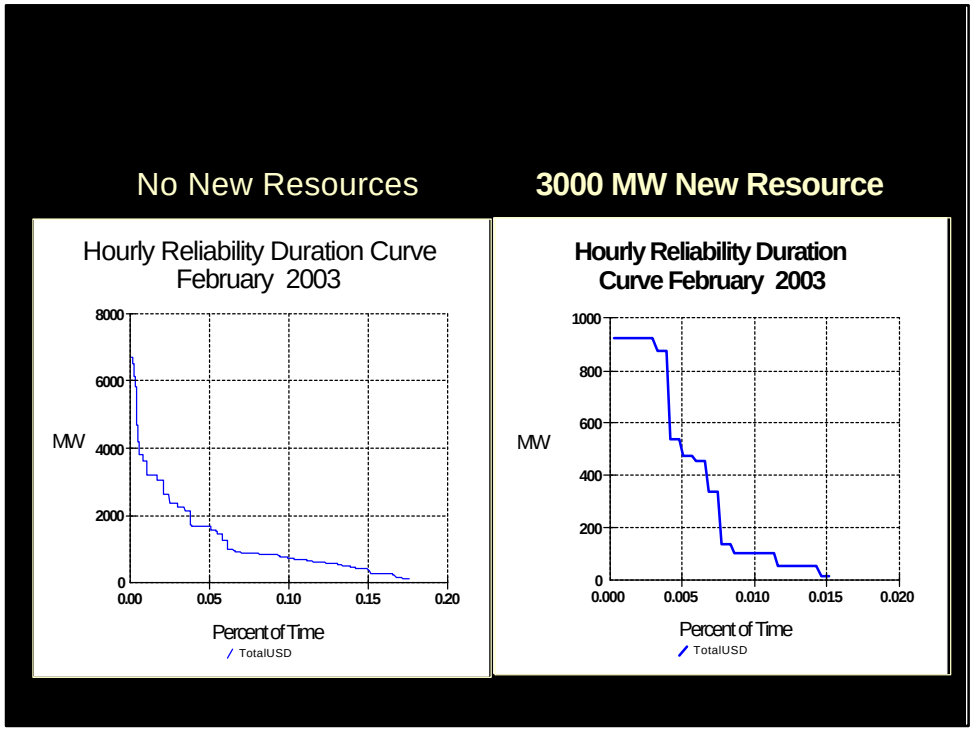
This chart shows the effect of adding new generation to the system on loss of load probability for the winter of 2003.

No new generation results in an LOLP of 24 percent, about a one in four chance of not making it through the winter.

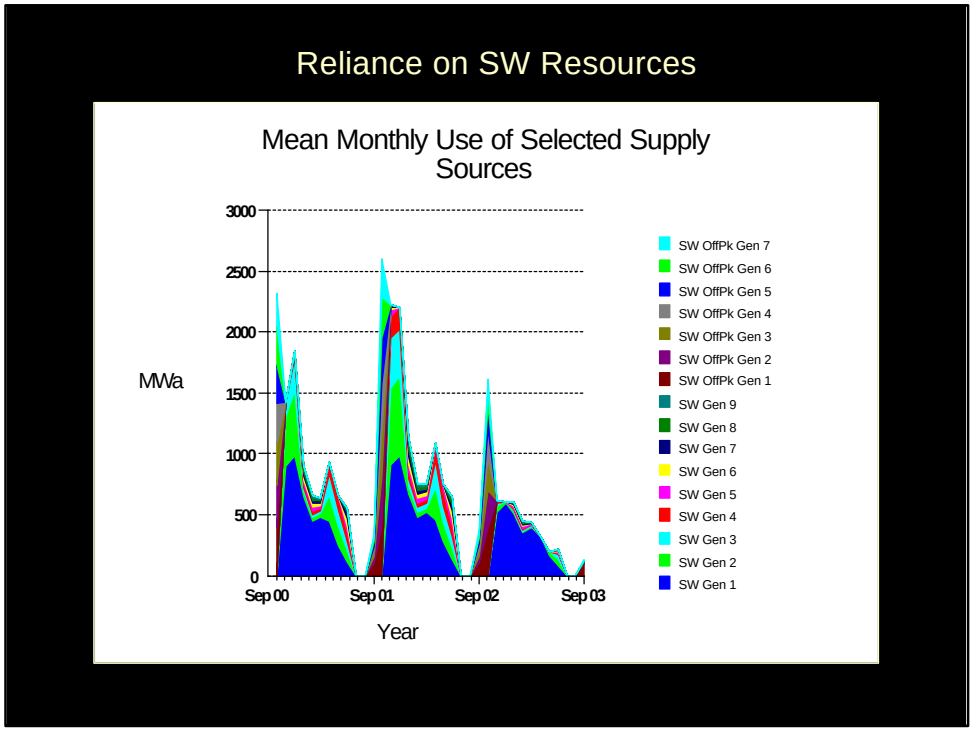
The Council believes this is an unacceptable risk for the Northwest power system.

Historically, utilities and regulatory commissions have used standards as high as one event in twenty years, which translates into an LOLP of five percent.

Attaining a one in twenty standard would require the Northwest to add almost 3000 MW of new, reliable generation or controllable demand side reduction resources by 2003.



Side by side chart shows that by adding 3000 MW of resources, both the size and frequency of outage events is reduced by about an order of magnitude.



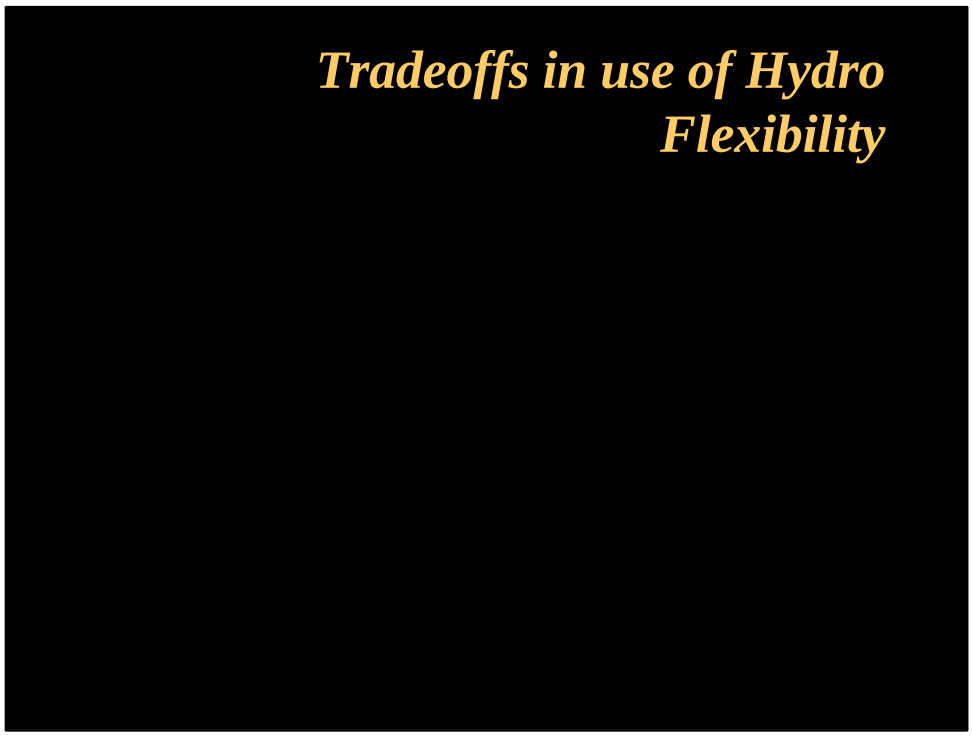
This chart shows the mean monthly reliance on California and Desert Southwest resources over the Sep, 2000 to August, 2003 time period, with 3000 MW of generation added in the last operating year.
Mean purchases are heaviest in the fall and early winter, and without new generation in the Northwest, approach 2500 MW on average.
Individual, poor water years, would show a much higher level of imports, continuing through most of the winter.

Factors requiring further analysis

- We have fairly high confidence in the conclusions presented
- There are, however, factors not included which could affect the results. These include:
  - Transmission constraints within the region
  - Intra-month stream flows
  - Availability of imports from Canada
  - Hydro generating unit forced outages

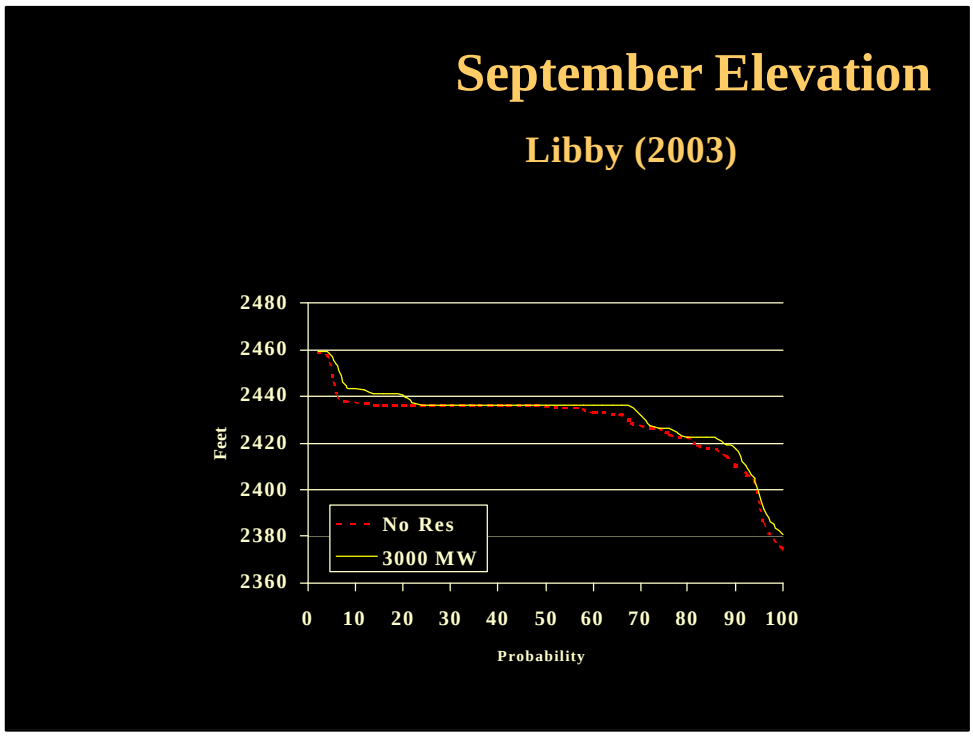
We have fairly high confidence that the analysis is giving a reasonable representation of potential power supply adequacy problems. There are, however, factors that deserve further analysis that could move the results to some degree. They include:

- Cross-Cascades transmission transfer capability — we have estimated that during a winter event, the 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 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 estimated that during cold events, British Columbia and Alberta will also be experiencing cold and will not have significant exports available for our use. If there are emergency operations that could make Canadian power available, it would reduce the magnitude and frequency of supply problems here.
- Hydro generating unit forced outages — while the model has the capability of incorporating hydro forced outages, further work needs to be done to separate the effects of forced outages from deferrable maintenance during a cold snap. Incorporation of hydro forced outages would increase the magnitude and frequency of problems to some degree.

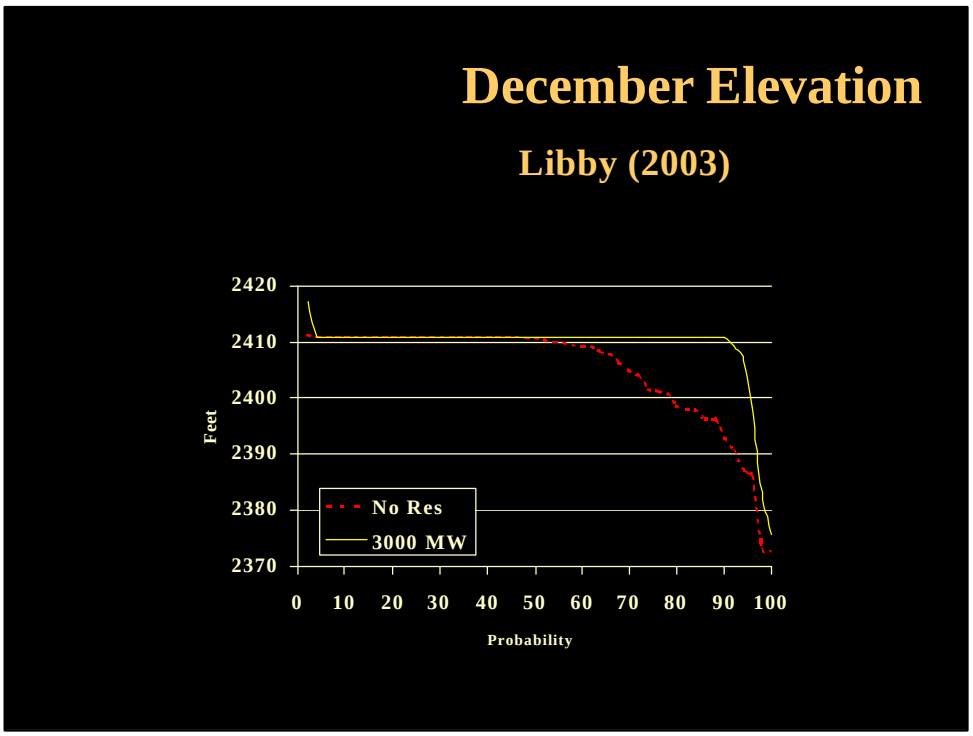


The preliminary results of our reliability study, with regard to fish and wildlife concerns, can be summarized as follows:

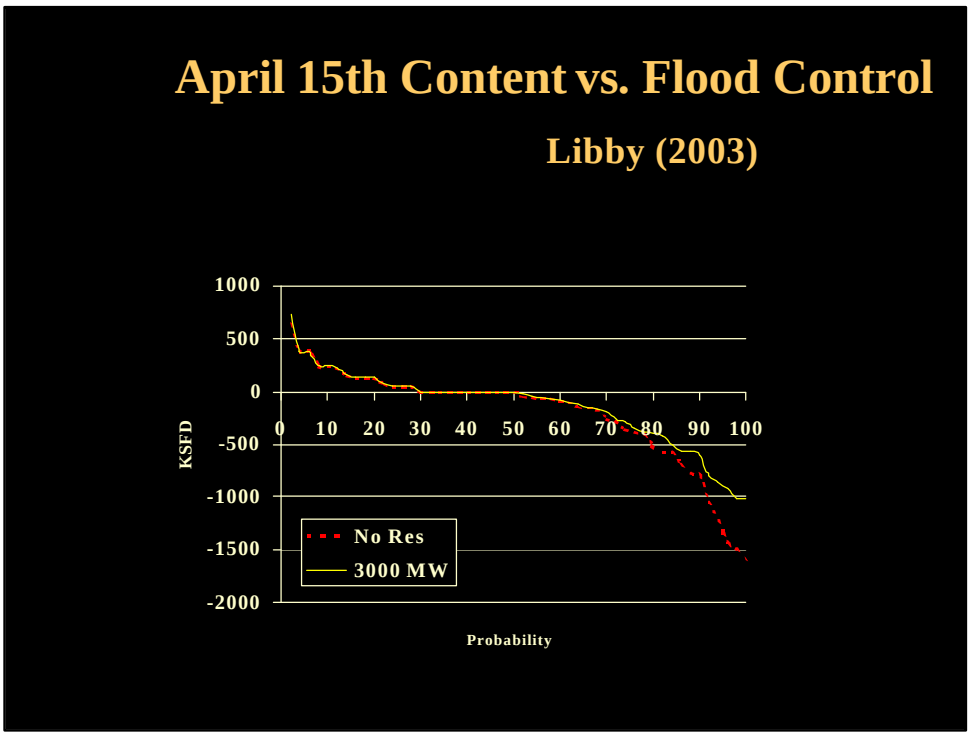
Practically speaking, it will not be possible to add significant new generating capacity in the Northwest for at least a few years. Beyond that period, it is not clear that the market will result in sufficient development to assure adequate supplies. This means that over the next few years, there is a higher probability that reservoirs will be drafted to undesirably low elevations during the winter months. 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. Longer term, without new resources, the result would be unacceptable.



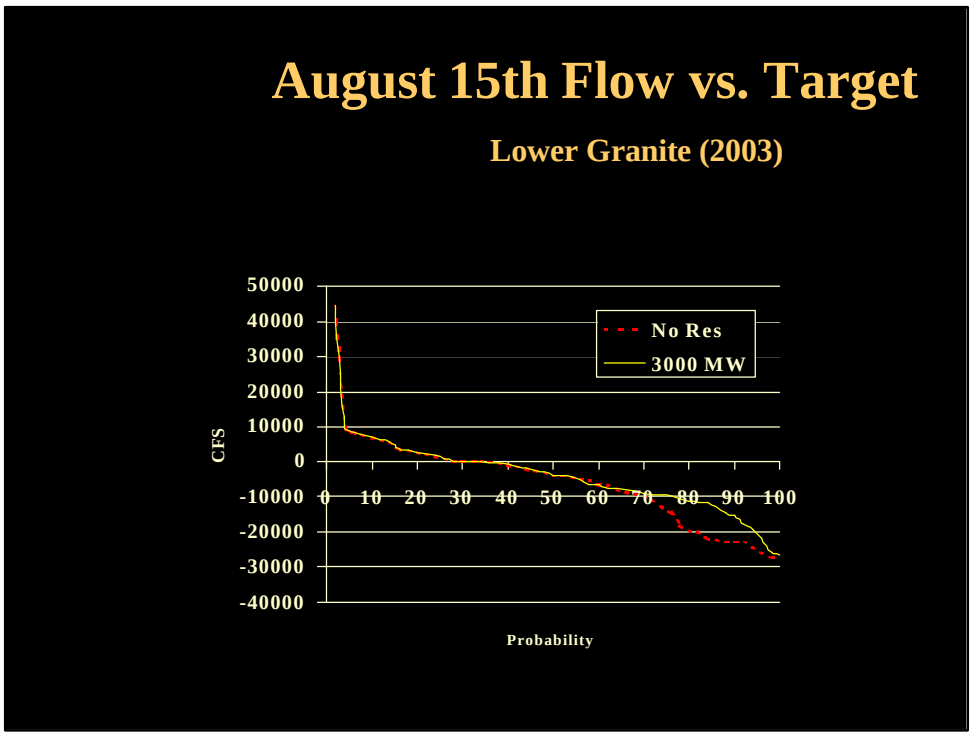
- The next six slides display what are commonly called "duration" curves. These types of graphs indicate the likelihood that some parameter will be at or above a certain level. In the graph above, for example, the curves show the likelihood of Libby Dam's reservoir being at or above a certain elevation in September of 2003.
- Two cases are shown in the chart above. The first (dashed red line) represents a scenario with no new resource development in the Northwest. The second case (solid yellow line) is a scenario in which 3,000 megawatts of newly installed resources are on-line by 2003.
- As an example of how to read the chart, examine the black 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.
- We are using Libby 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.
- In general, we can conclude that there is about a 70-percent chance that Libby will be lower in the "no new resource" scenario (about 70 percent of the time, the dashed line is below the black 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 (worst case was 14 feet).



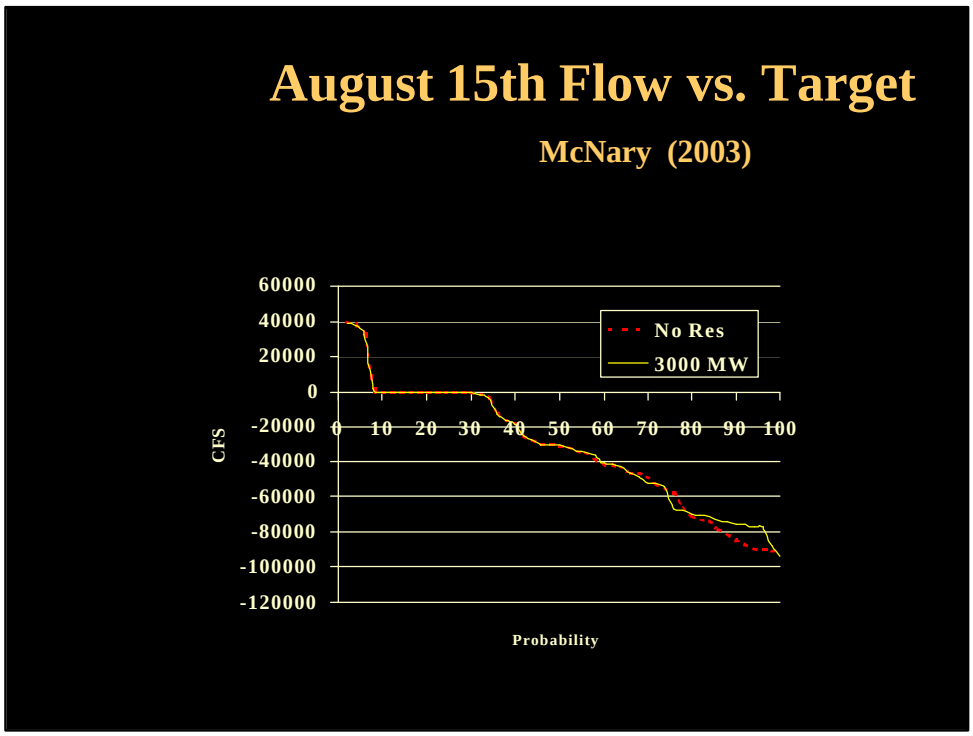
- This slide presents the December elevation probability curves for Libby in 2003.
- Although the scale in this chart is different from the one in the previous chart, it should be obvious that the impacts of not including new resources are more severe than in September. This is true because demand for electricity in the Northwest normally peaks sometime between December and February.
- 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.



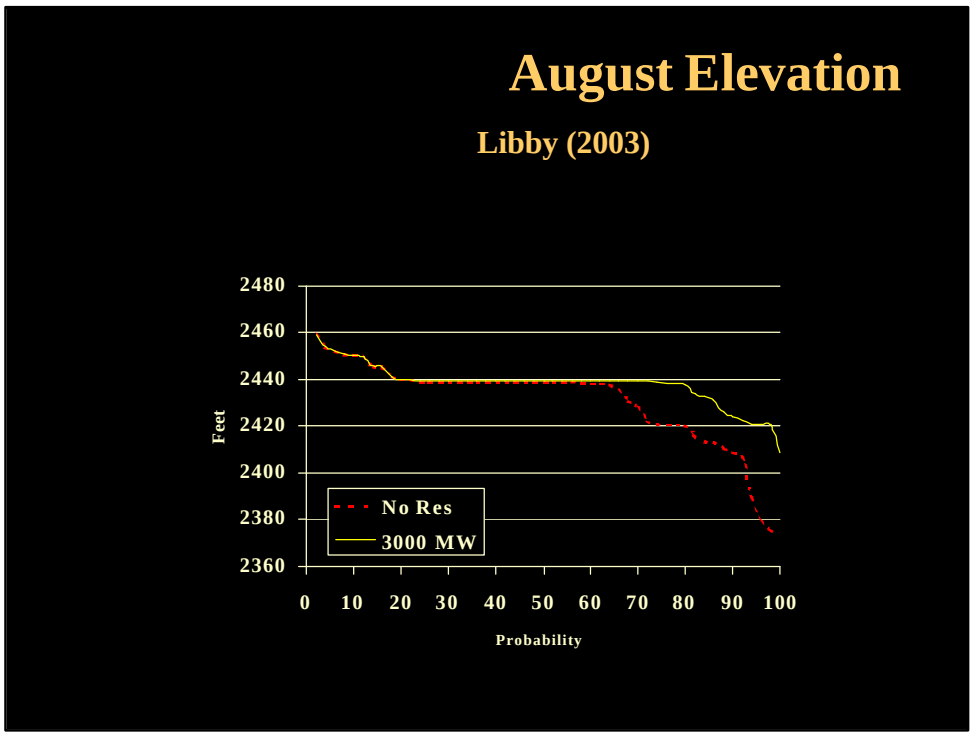
- The more severe drafts in winter months under the "no new resource" scenario can often be made up by mid-April when the salmon migration typically begins. (Water is restored by reducing flows and importing energy from out of region or from non-hydro resources).
- The graph above is also a probability chart but unlike the previous charts, it presents the likelihood that Libby will be "as full as possible" by mid-April. The curves above 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 will be operated to. This is intended to provide a space for the expected snow-melt runoff and protect against flooding.
- In Libby's case, it can sometimes be at higher than flood control elevations 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 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.



- 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.
- The impacts of this shortage appear in the chart above, 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.)
- About 40 percent of the time, flows are likely to be lower at Lower Granite Dam under the "no new resource" scenario. In years when flows are lower, they average about 4,500 cubic feet per second lower. In the worst case, the flow is nearly 10,000 cubic feet per second lower. (The target flow at Lower Granite in this month is 50,000 cubic feet per second.)



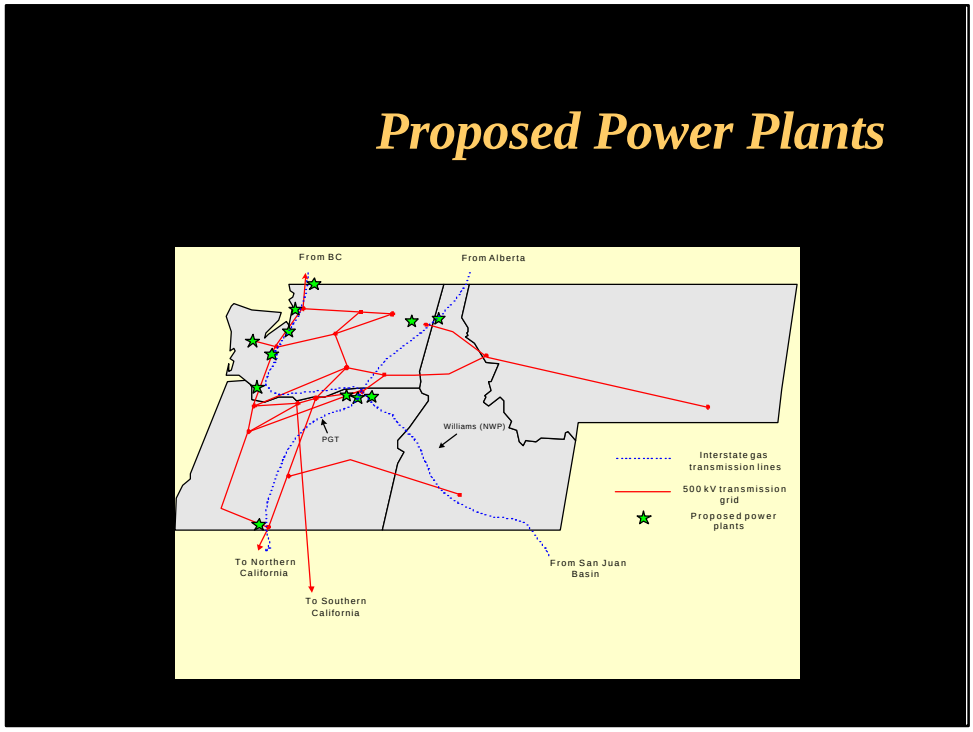
- In looking at the flows at McNary Dam, we observe the impacts of actions on both the Snake and Columbia rivers. About 22 percent of the time, flows are likely to be lower in the "no new resource" scenario at McNary in the first half of August, 2003. (About 22 percent of the time, the red dashed line is below the solid black line).
- In years when flows are lower, 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. (The biological opinion flow target at McNary for this period is 200,000 cubic feet per second).
- 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 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. The last chart on the next page illustrates what is going on.



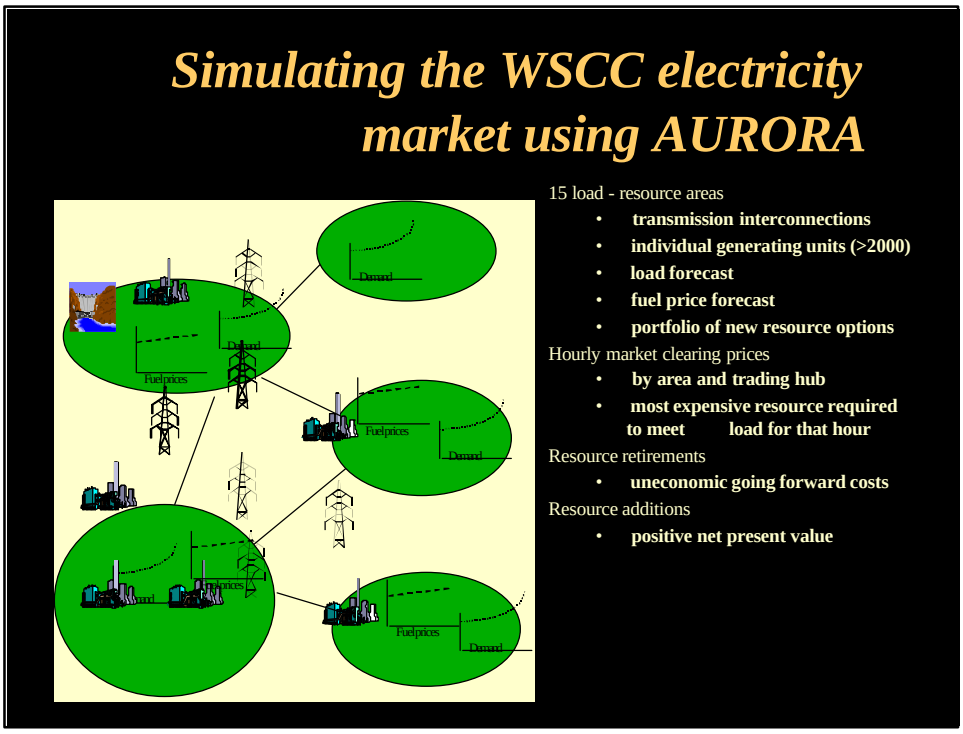
- This chart (similar to the first two) shows the elevation probability at Libby Dam for the end of August in 2003. About 44 percent of the time, Libby will be lower in the "no new resource" scenario. In years when it is lower, it will be 17 feet lower on average. In the worst case, Libby is 45 feet 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 above, the solid black 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 (red dashed line), Libby is below the biological opinion draft limit nearly 40 percent of the time. It is safe to assume that in each case where the red dashed line is below the solid black line, that Libby was used for power needs and not for flow augmentation.
- Remember that impacts at other reservoirs are similar to those presented here for Libby.
- In conclusion, relying too heavily on the hydro system for reliability concerns results in a higher probability that reservoirs will be at undesirably lower 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.

Forecast Power Plant Development Activity

An important element of the adequacy and reliability study is the forecast availability of generating resources during period of interest. This requires an inventory of current generation and a forecast of project additions and retirements. The next several slides describe the forecast of future power plant development activity.



We have an inventory of existing generating projects, and reasonable understanding of the type, location and size of new power projects that could be constructed in the Pacific Northwest. What we do not know is how many of these projects might be built and when they would enter service. The map shows power projects under construction, sites currently permitted for construction of projects, and sites for which permits for construction are being sought. All of these proposals are for natural gas-fuelled combined-cycle gas turbine power plants, ranging in size from about 250 to 800 MW.



We use AURORA™, a model of the western North America power system developed by EPIS, Inc., to forecast resource retirements and additions. AURORA was developed to forecast wholesale electric power prices. AURORA can also be used to forecast the the development (and retirement) of generating resources in response to market prices.

The Western Systems Coordinating Council (WSCC)electricity system is modeled as 14 geographic load-resource areas, generally defined by transmission constraints. Each area is characterized by its inventory of generating units, fuel price forecasts, load forecasts, and a portfolio of new resource options. Transmission interconnections between the load-resource areas are characterized by transfer capacity, losses and wheeling costs.

Aurora forecasts hourly market clearing prices by dispatching generating units to meet forecast loads. Dispatch is based on the variable cost of operation. A unit may serve its own area, or considering transmission options, other areas. Hourly area electricity prices are established by the variable cost of the most expensive resource dispatched to meet that area's load.

A schedule 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.

Key Assumptions

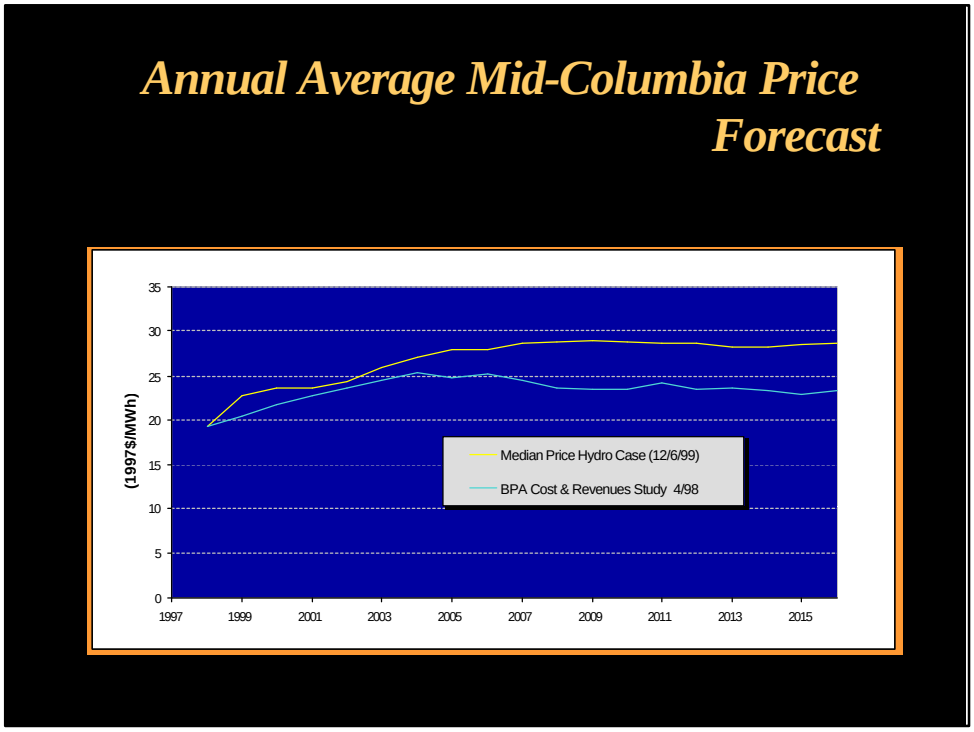
- New projects are developed by private, independent developers.
- Projects under construction are completed; development of additional projects is market-driven.
- Projects scheduled for retirement are retired; additional retirements market-driven.
- "Mean price" water conditions.
- Henry Hub year 2000 gas price $2.40/MMBtu.
- Average load conditions.
- No significant transmission upgrades.
- 1.5 c/kWh incentive for renewables development.

Because new generating resource development is now predominantly undertaken by independent generating companies, we assume that projects will be developed under financial conditions representative of this type of developer. We assume that projects currently under construction are completed as scheduled, and that proposed retirements reported by WSCC occur as scheduled. Other project additions and retirements are market-driven, as forecast by AURORA.

Hydropower conditions can strongly affect wholesale electricity prices. Moreover, this relationship is asymmetrical; price increases during poor water conditions are greater than the decline in prices under good water conditions of equal probability. We assume that project developers will tend to base development decisions on expected future prices. Because stochastic modeling of water conditions is difficult in AURORA, we use a "slightly dry" water condition to model mean wholesale prices.

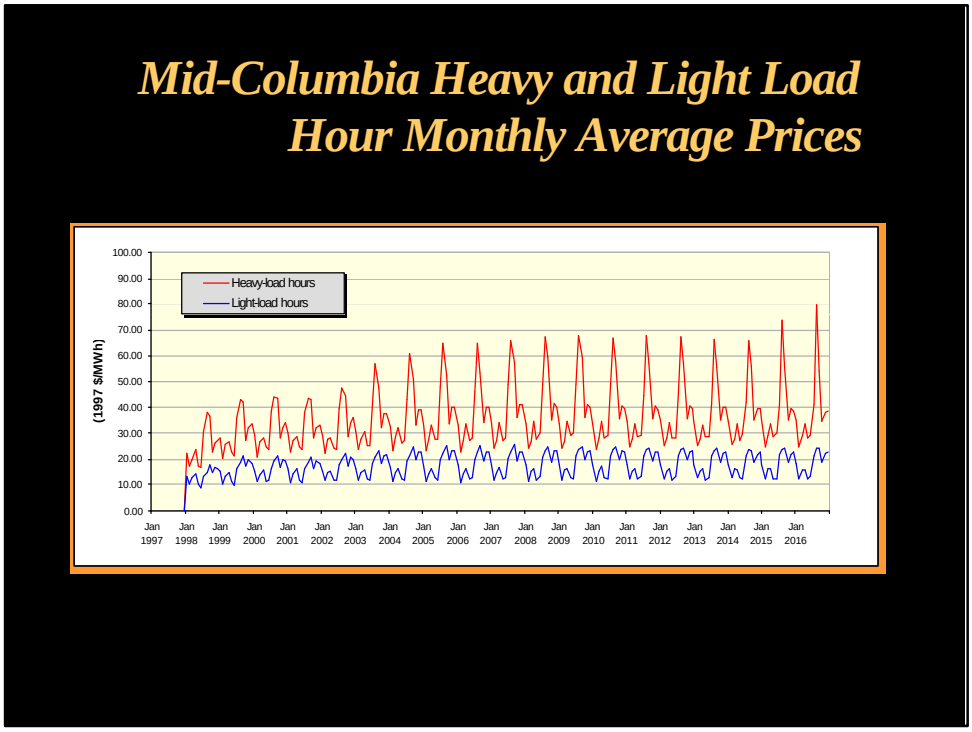
Natural gas price forecasts have been revised upward to reflect recent trends. The Henry Hub gas price for 2000, for example, is $2.40/MMBtu, compared to $2.05/MMBtu for the Council's 1998 forecast of BPA costs and revenues.

A production credit of 1.5 cents/kWh extending through 2010 is used as a proxy for activities intended to promote renewable resources.

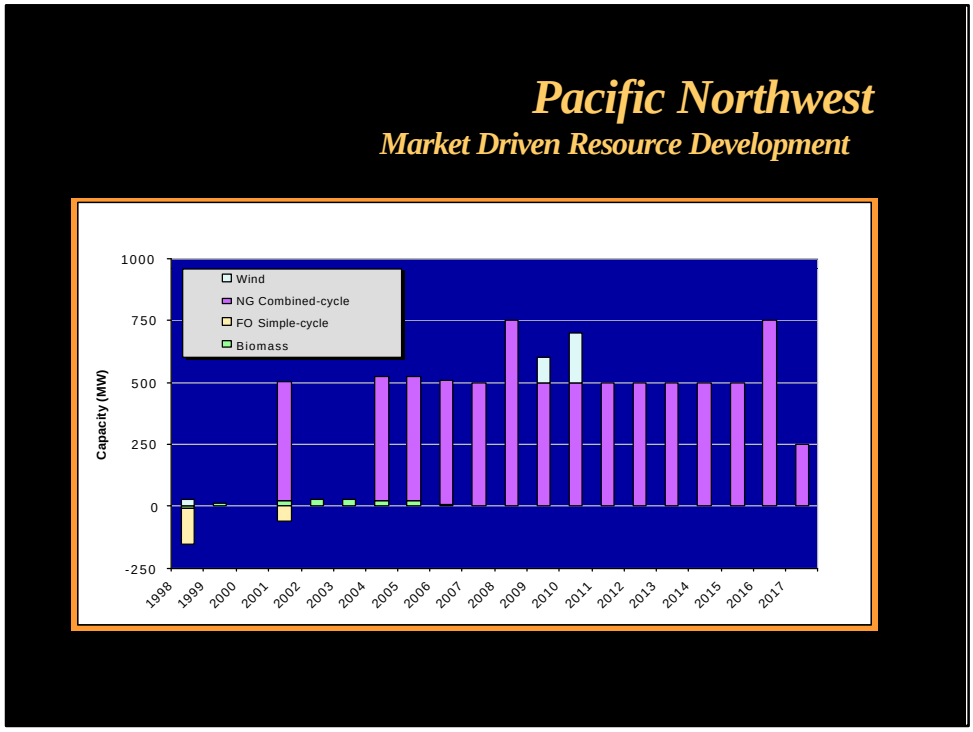


AURORA calculates wholesale prices at the major trading hubs. The Mid-Columbia trading hub is representative of Pacific Northwest prices. Prices (and resource development schedules) are forecast over a 20-year period to minimize end-effects for the 2000 - 2006 period of interest.

The yellow curve is the current forecast (in constant 1997 dollars) of average annual Mid-Columbia prices. The current forecast runs generally higher than the base case forecast prepared for 1998 Council assessment of BPA costs and revenues (blue curve). Higher fuel price forecasts and other revisions to assumptions and the model lead to the difference between the electricity price forecasts. The overall form of the forecast is consistent between the studies. Low early-year prices gradually increase as load grows, forcing the dispatch of less-efficient resources to meet peak period loads. As new resources (primarily gas-fired combined-cycle units)are developed, average prices level off at the fully-allocated cost of these new resources.



This chart shows the Mid Columbia hub price forecast in additional detail. Average monthly loads for heavy load hours and light load hours are plotted separately. Increasingly strong peaks are observed in the late summer months. These are produced by the influence of daily air-conditioning loads in the Southwest. This peaking pattern has been evident over the past several years in western power markets.

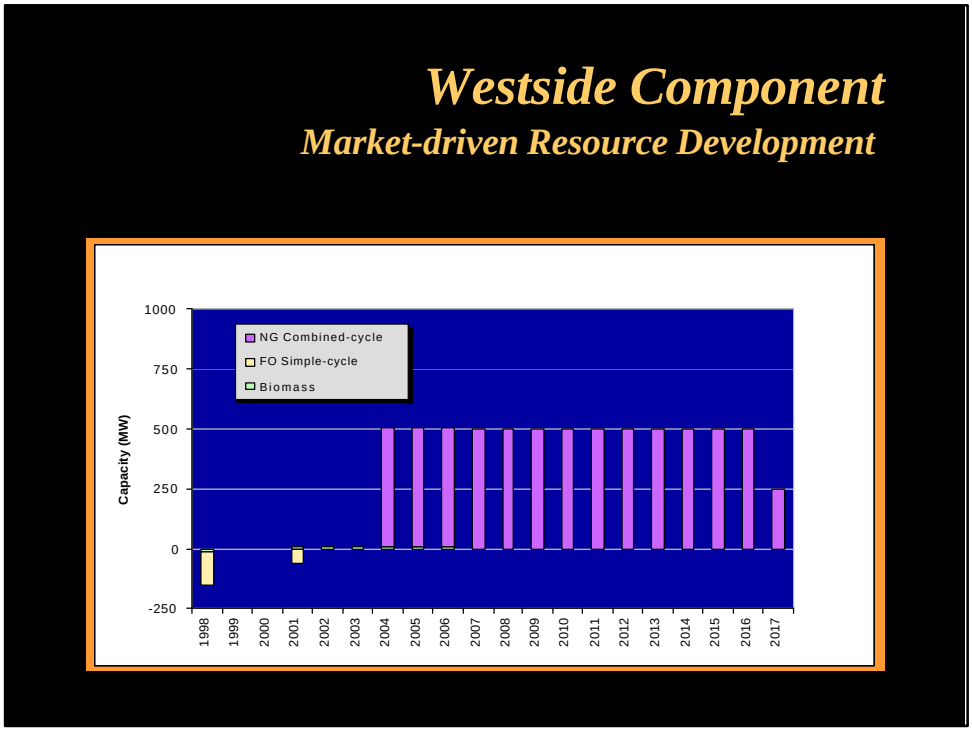


This aggregate resource development forecast for the Pacific Northwest includes the load-resource areas of western Washington & Oregon, eastern Washington and Oregon and northern Idaho, southern Idaho, and Montana.

Several older, inefficient oil-fired gas turbines and a biomass unit are retired in early years (these retirements have occurred). Scheduled additions include the Vansycle wind project in 1998, the Klickitat landfill gas facility in 1999 and the Klamath Falls combined-cycle project in 2001. Small-scale additions of landfill gas units, driven by the production credit assumption continue through 2005. At that time the estimated inventory of this resource is exhausted.

Beginning in 2004, gas-fired combined-cycle units are forecast to be added at the rate of 500 to 750 MW per year. Blocks of wind turbines are added in 2009 and 2010, after which the assumed renewable production incentive expires.

The timing of the earliest market-driven combined-cycle addition (2004) is intuitively late given current levels of developer activity in the Northwest. However, this date is fairly insensitive to factors likely to affect the the timing of market-driven development.



Most of the forecast resource additions shown on the previous slide occur in the Western Washington and Oregon load resource area. This area is currently severely resource-deficit and is likely to experience continuing load growth. As-modeled, the area has transmission access to seasonally complementary loads in the southwest and enjoys relatively lower gas prices than southwestern areas. These factors favor future generating resource development.

The constant (500 MW/year) market-driven resource development rate may result from somewhat arbitrary build limits established for the area. The consequences of relaxing this build limit are being investigated.

Conclusions

- Forecast market prices and resource development patterns are sensitive to:
  - Assumptions regarding cost and quantity of voluntary load curtailment.
  - Water conditions (skewed, non-linear response)
  - Fuel price forecasts
- Forecast market prices and resource development patterns appear to be fairly robust across other variables.
- Difficult to fully capture project-specific development factors.

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, water conditions and fuel prices. The cost and availability of voluntary load curtailment is poorly understood and fuel price forecasts are highly uncertain. While the long-term distribution of water conditions is better understood, the decisions of developers (and their financial backers) may be affected by recent better-than average water conditions, the unknown water conditions of the next several years, or evidence that the Northwest has entered a period of wetter-than-normal conditions.

Other factors lend uncertainty to the resource development forecast. Project development in the deregulated generating industry is a game where it pays to to preempt competing projects, yet not develop so early that electricity prices will not support project costs. Some developers, however, may have the 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. These factors are not easily captured in a model that seeks perfect economic timing of new projects.

Bottom Line

- Region needs to get serious about how it can:
  - Support new generation development for reliability

    AND
  - Find ways for end-users to provide reliable,voluntary economic load reduction
    - Can be counted on when called for
    - Makes economic sense for the end-user

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

The supply side is an important component of these discussions. Does the region need to take steps to support the development of generation for reliability purposes and, if so, how, at what cost and with what effects on the market?

Given the proximity of the potential problems and possibly for reasons of economy, the demand side needs to be addressed as well. Many believe that as end-users see market prices directly, they will reduce their demand in response to high prices sufficiently to avoid problems. Industrial and large commercial customers are most likely to see market prices and may be most able to respond to price signals with significant load reductions.

However, how long will it take for market prices to work their way through to most end-users and to see how end users respond? In the near term, we may have to examine other ways for the demand side to participate in achieving load-resource balance. There are a variety of approaches one could envision. They need to be reliable — the load reduction needs to occur when needed, they should be voluntary, and they should make economic sense for the participants.