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Analysis of Winter 2001-2002 Power Supply Adequacy

1.0 Overview

The Council released its last assessment of Northwest power supply adequacy for the winter of 2001-2002 in early June of this year. That assessment relied on data, assumptions and analysis largely developed over the previous month. It found that given the then-current assessments of the demands for electricity across summer and subsequent fall and winter, new generation, and hydro conditions, the probability of winter season power supply inadequacy was approximately 17 percent.[1] The analysis went on to assess the efficacy of storing additional energy in Arrow reservoir in Canada in reducing winter power supply problems. It was found that storing an additional 1,500 megawatt-months of energy (in addition to 1,200 megawatt-months already planned to be stored) reduced the probability of inadequacy to about 12 percent. Additional amounts of storage did not significantly reduce the probability, largely because of restrictions on the rate at which water could be withdrawn from the reservoir. On the basis of this and other similar analyses, decisions were made to dramatically reduce spill at federal hydroelectric projects and seek additional opportunities for reducing electricity demands.

The Council recently completed a reassessment of the winter power supply situation based on updated data and analyses. This analysis found the probability of winter season power supply inadequacy to be well under the target level of 5 percent. This is attributed primarily to two factors. First, expected demands for electricity are significantly lower than estimated in the May analysis. This is attributable to several factors: efforts on the part of utilities to buy out industrial loads, particularly the aluminum industry; conservation efforts, the expected effects of retail rate increases and the general slowdown of the economy. The other major factor is improved hydro storage conditions. Instead of 1,500 megawatt-months of energy stored in Canada, 3,700 megawatt-months were stored.[2] This additional storage was made possible by the drastically reduced spill this summer and by the fact that loads were lower that expected throughout the West. In

[1] The winter season is defined as the months of December, January, February and March. A winter season was judged to have an inadequate power supply if loads exceeded available energy by a seasonal average of 10 average megawatts or more.
[2] This is in addition to the storage of 1,200 megawatt-months of energy that was already planned and was included in both the May and October studies.

addition, the constraints on the rate at which this energy could be withdrawn were relaxed, making the stored energy more effective in addressing periods of high demand.

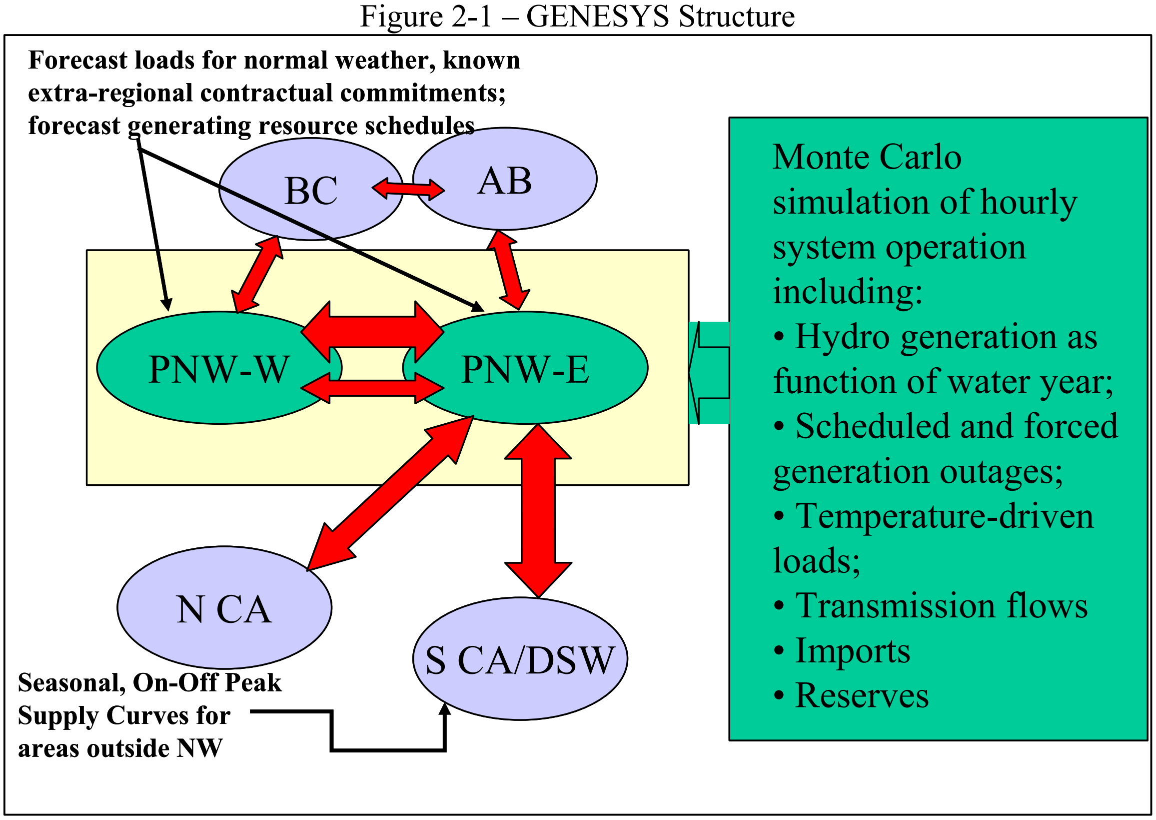
The analysis and the results are described in more detail in the following sections.

2.0 Modeling System

Power supply inadequacy is generally the result of a combination of adverse events. Energy shortfalls are typically the result of a combination of low hydropower production as a result of poor water conditions, high loads as a result of extreme temperatures, reduced thermal powerplant output as a result of forced outages and the inability to fully compensate for these factors with additional energy from either regional resources or imports. It is possible to conduct a scenario analysis that shows that if certain conditions occur, there is or is not a problem and the magnitude of that problem. However, that does not predict how likely such a situation is. To determine the probability of power supply being inadequate, it is necessary to look at the probability of circumstances combining to cause the situation.

The Council's power supply adequacy studies have used a Council-developed model of the Northwest power system called GENESYS. The structure of the model is illustrated in Figure 2-1.

Figure 2-1 – GENESYS Structure



GENESYS models the operation of Northwest power system in detail. It can be run for different time intervals down to hourly simulations. The important stochastic variables are the hydro conditions, temperatures as they affect electricity loads and forced outages on thermal generating units (both occurrence and duration). The model runs hundreds of simulations of the study period. For each simulation it samples hydro conditions, temperatures and the outage state of thermal generating units according to their probability of occurrence in the historic record. The percentage of simulations that result in resource inadequacy is the probability of inadequacy or "loss of load probability". The output can also be analyzed to look at the frequency of problems as a function of their magnitude.

The model splits the region into an eastern portion and a western portion to capture the possible effects of cross-Cascade transmission limits. A monthly load forecast corresponding to "normal" temperatures is an input to the model. The model shapes monthly loads to sub-daily loads for the East and West parts of the region for the temperature year being modeled. The amount of non-hydro generation in the region is also an input to the model as are contractual commitments for import or export from the Northwest and the availability of additional spot-market imports to the region.

An important feature of the model is the ability to model the operation of the system more like it would actually be run in an emergency situation. In such a situation, the hydro system would be drafted deeper to meet loads. Operators would subsequently try to restore reservoir levels by running thermal units harder and purchasing imports.

In the following sections, the assumptions and analyses going into the inputs for the model for the winter 2001-02 period are described.

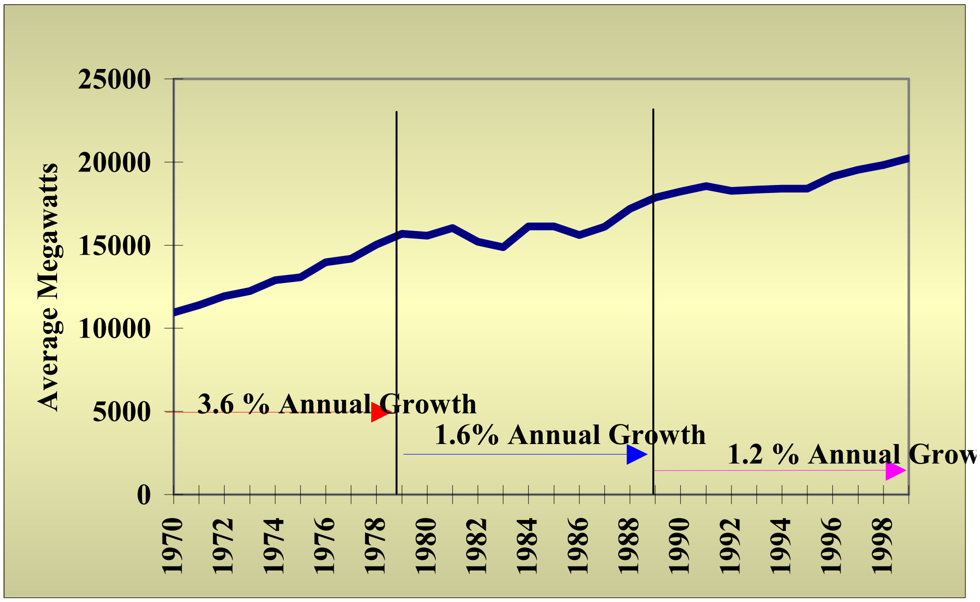
3.0 Demand Forecast

3.1 Recent Electricity Demand Patterns

Before trying to predict future electricity demand, it is important to look at where it has been and how it has responded to the recent chaos in western electricity markets.

Figure 3-1 gives a long-term perspective on regional electricity demand growth. The first growth interval illustrated in Figure 3-1 is 1970 to 1980. During this period, electricity use grew at 3.6 percent annually. This was a substantial reduction from the growth rates experienced in the previous 20 years; from 1950 to 1970 electricity demand grew by about 7 percent a year, adding over 400 megawatts of demand each year. Although the growth rate was cut in half during the 1970s, the number of megawatts added to demand each year increased to 500 megawatts per year, a result of growing from a larger base.

Figure 3-1
Total Regional Electricity Sales



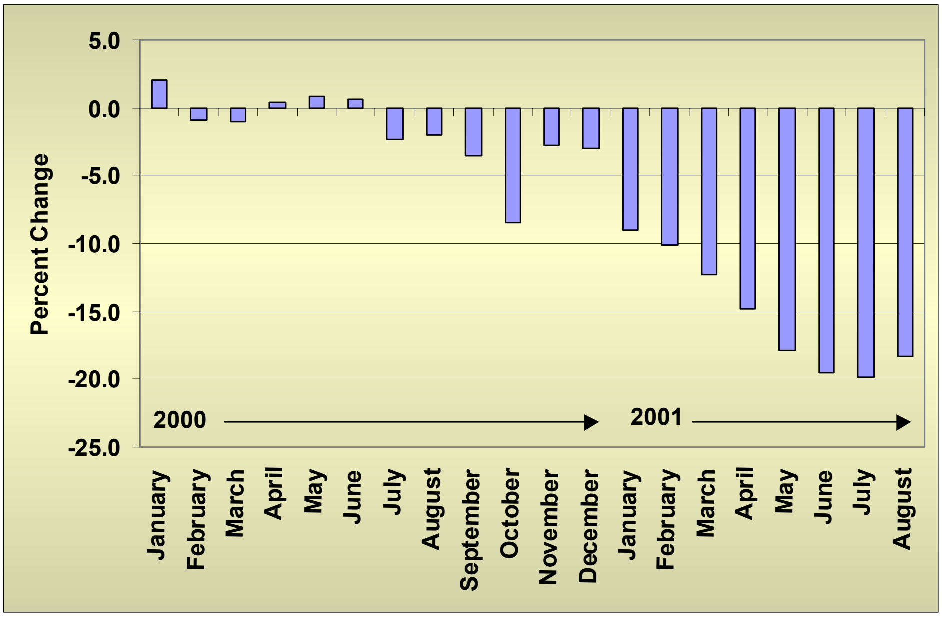
Beginning in 1980, the region experienced a watershed in terms of electricity demand growth. The growth rate halved again and the number of megawatts of demand added each year fell to 300, from 500 in the previous decade. In some ways the influences acting on electricity demand in the early 1980s are similar to current conditions. Regional power costs increased by nearly 500 percent between 1979 and 1984, and the region experienced a serious economic downturn during 1982 and 1983. Growth during the 1990s has averaged 1.1 percent annually, adding only 220 megawatts of demand each year.

The long-term electricity demand forecasts in the Council's Fourth Northwest Power Plan medium case grew at 1.3 percent per year from the 1994 actual level to the year 2015. Evaluation of those forecasts during the late 1990s shows that the forecasts are tracking actual demand quite closely through 1999.[3] However, recent events are causing a cyclical departure from the Council's long-term forecasts that will continue for the next few years.

Figure 3-2 illustrates the magnitude of demand reductions that have taken place in recent months. The figure shows the percent change in temperature-adjusted electric loads from the same month in the previous year. Significant declines started in the second half of 2000 and reached a decrease of 20 percent for July 2001 from July 2000 levels. This amounts to a decrease of about 4,000 megawatts of load.

[3] "Economic and Electricity Demand Analysis and Comparison of the Council's 1995 Forecast to Current Data." Council Publication 2001-23, September 2001

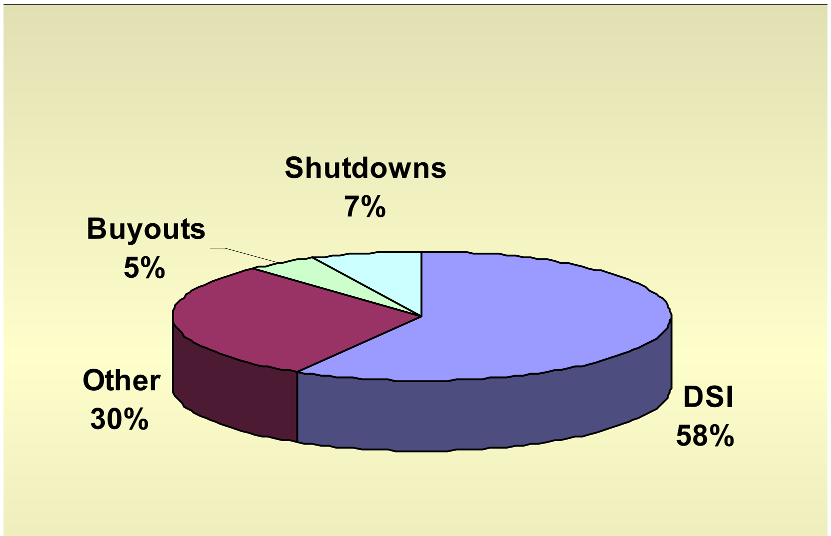
Figure 3-2
Monthly Load Changes from Previous Year



Seventy percent of this load reduction was a result of large electricity-using industries closing, most notably aluminum smelters(see Figure 3-3). Bonneville or other regional utilities bought out many of these loads in order to save money on expensive power purchases. Some of these buyouts were of irrigation loads during the summer months.

The other 30 percent of load reductions were savings by residential, commercial, or smaller industrial users. Retail consumers had seen price increases on average of about 9 percent by July 2001 and their response with about a equal percentage drop in demand is a greater demand reduction than would be expected based on typical short term price elasticity estimates. The larger demand response was undoubtedly due to a high degree of publicity surrounding the California market problems, high wholesale electricity prices, Governors' appeals for conservation, and enhanced utility conservation programs. Combined, these factors probably reduced demand by the equivalent of four 250 megawatt combined cycle power plants.

Figure 3-3
Composition of Summer 2001 Load Reductions



3.2 Load Forecasts

3.2.1 Methods

The basic hypothesis in predicting how loads might behave over the next few years is that loads will return to the long-term forecast trend over the next two to four years. There are several key factors to consider:

- The effects of further retail price increases
- The extent and duration of the economic recession and its effect on loads
- The effect of sharply lower wholesale prices and the avoidance of outages last summer
- Potential renegotiation of buyouts and their timing
- The duration of recent retail price increases in the face of dropping wholesale prices
- The persistence of electricity use reductions that are not the result of "permanent" measures (e.g., installing a more efficient water heater) as prices are lowered from crisis levels
- The effect of currently depressed aluminum prices on resumption of aluminum production.

For the present, the forecast is limited to one path. This is not to imply that there is great certainty about the forecast. The effects of the factors listed above are not known with any certainty. The forecast is intended to reflect a realistic future, but it is also intended to be somewhat optimistic about the recovery of electricity loads. When exploring the reliability of the electricity system it is prudent to erron the high side of demand while not being overly optimistic because errors on either side of future demands have potential costs for the region.

The Council has no models that are practical and useful for addressing the near-term future of electricity loads. Therefore the forecasts are judgmental and intuitive. The approach has been to try to predict the further reduction and recovery of each of the major categories of load reductions shown in Figure 3-3. The return of direct service industry loads (primarily aluminum smelters), bought out industries and other large industrial shutdowns were each assumed as to timing and degree. Similarly, the pattern of recovery for the remaining loads has been hypothesized. The assumptions reflect thinking about the factors listed above, but the links are not direct or automatic in the absence of some type of model to tie the assumptions to the results.

3.2.2 Results

The electricity load forecast approach and results are summarized in Figure 3-4. It shows the Council's Fourth Northwest Power Plan forecast allocated to monthly patterns in the upper line. The lower line is the new short and mid-term forecast. The forecast shows a recovery from the current situation, shown in the shaded area of the graph, back to the long-term trend forecast of the Fourth Northwest Power Plan. Loads remain depressed through the remainder of 2001 and into the middle of 2002. In mid-2002, loads begin to recover toward the long-term trend. By 2004 the mid-term load forecast has nearly recovered from the recent electricity crisis and the economic weakness of the economy.

The forecast is generally consistent with the expectation of an economic recession that stretches through the first quarter of next year. It also reflects an assumption that although retail prices of electricity have increased significantly more in the past weeks than in the year to date, the impact on demand will be more in line with traditional elasticity estimates than what has been observed to date this year. The reasoning is that (1) the crisis is widely believed to be a thing of the past and will receive far less attention, and (2) that wholesale prices have fallen to low levels and will exert less influence on utilities and large consumers that may be exposed to wholesale prices. At the same time, the economic recession and the depressed state of the aluminum industry will likely delay the reopening of most electricity-intensive plants until at least next spring or summer even though relatively low-priced wholesale electricity may be available.

Figure 3-4
Total Regional Electricity Loads

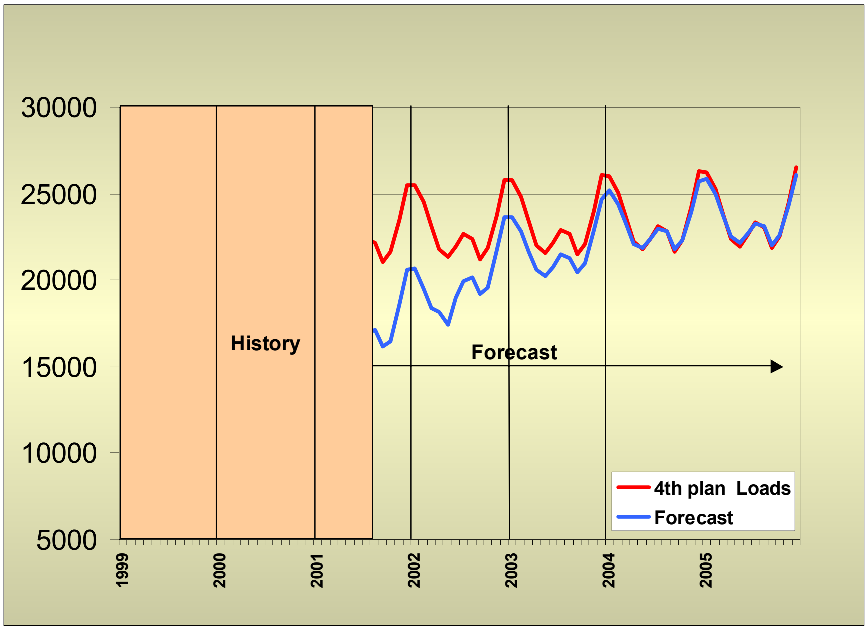


Figure 3-5 shows the difference in the demands used in the May study compared with those in the current study. Some of the difference is attributable to assumptions about the DSI loads. At the time of the May study, not all of the direct service industries had signed buy-back contracts and it was believed that it was possible some of them could put load back on as early as October. The May analysis also did not take into account quantitatively the several factors noted earlier that could keep loads down through this winter.

Figure 3-5
Comparison of Loads from May and Current Studies

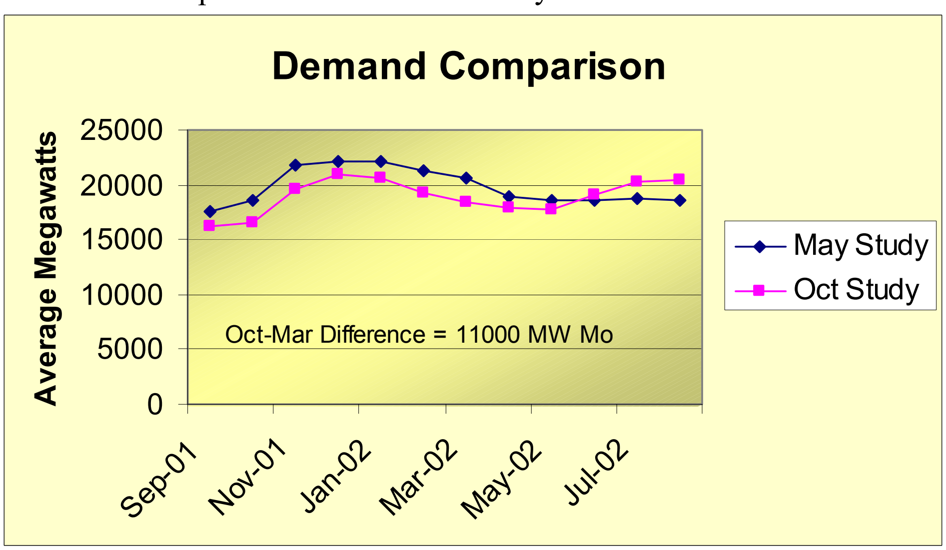
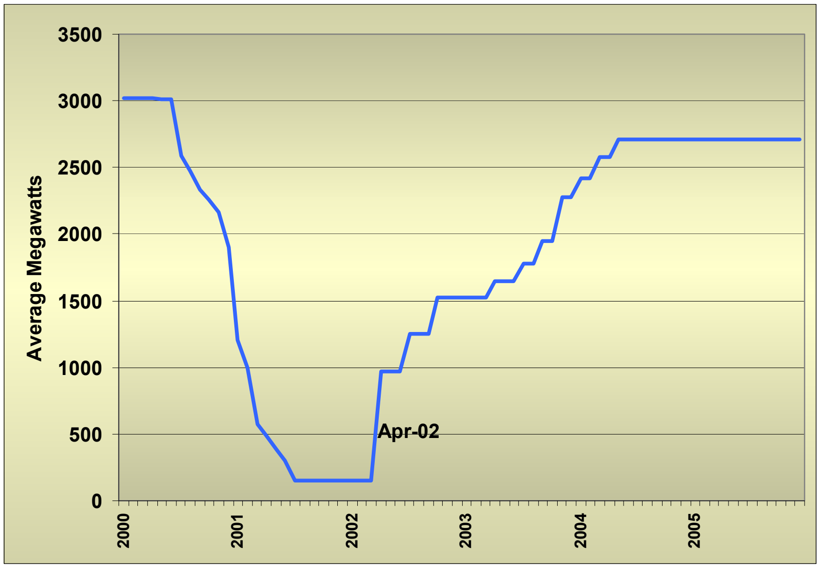


Figure 3-6 illustrates the assumed recovery of the Bonneville direct service loads. A couple of the most viable plants come back on line in April 2002 with additional restarts spread over the next couple of years. It is not expected that all aluminum plants will return to production in the long run. Other large consumers that were bought out or shut down are assumed to fully recover by September 2002.

Figure 3-6
DSI Load Assumptions



4.0 Hydro Conditions

For a reliability assessment, three factors are important: the initial reservoir contents for the U.S. reservoirs at the beginning of the water year (September 1) the amount of additional energy that may have been stored by mutual agreement in Canada's Arrow Lake and the runoff volume.

4.1 Storage

The hydroelectric system's annual operation begins in September when reservoirs should be at their highest elevations, in anticipation of the peak demand season. This year U.S. reservoirs effectively refilled to the levels specified in the Biological Opinion (BiOp). This is what was assumed in the May analysis. In addition, water equivalent to approximately 3,700 megawatt-months of energy was stored in Canada's Arrow Lake. This is 2,200 megawatt-months more than was assumed in the May analysis. This was made possible by the reduction in spill at federal projects across the summer as well as lower than anticipated summer loads throughout the West.[4] In total, approximately 7,000 megawatt-months of energy that normally would have been spilled to aid the downstream migration of juvenile salmon and steelhead, was not spilled. That energy was used to meet loads, particularly in the late spring and early summer when much thermal

[4] Spill passes water over dams rather than passing water through the turbines to produce electricity.

generation was down for scheduled maintenance; to help restore reservoir contents to desired levels after they had been drafted deeply in the early summer to meet loads; and to allow the storage of energy in Canada.[5]

There is another difference from the May study, a change in the Canadian operation for this winter. The operation of Canadian reservoirs is guided by analysis done jointly by U.S. and Canadian entities. Under the Columbia River Treaty, very specific constraints are used to produce operating rule curves for Canadian reservoirs. The operation of Canadian reservoirs is then held constant for any scenarios involving U.S. operations. The Canadian operation used in the current analysis shows higher outflows from Canada in December and January and lower outflows in February. The higher outflows increase U.S. hydro capability in those months.

4.2 Runoff

The runoff forecast is also important because of the great variation in energy production between dry and wet years. On average, the hydroelectric system produces about 15,800 average megawatts of energy annually. In the driest year, it produces only about 11,800 average megawatts -- a difference of about 4,000 average megawatts, enough to power more than threecities the size of Seattle. Assessing the Loss of Load Probability (LOLP) for the 2002 winter season depends highly on the anticipated runoff conditions.

How we approach runoff estimates is in part dictated by the characteristics of our analytical system. Our system explicitly accounts for the variability in the output of the hydro system. The approach is to do Monte Carlo simulations of the operation of the system where historical runoff conditions associated with specific water years are one of the stochastic variables (along with forced outages and temperatures). We do not yet have the capability of running so-called synthetic water years for a large number of conditions.[6] Secondly, once we have begun a simulation, we can't (and it would make no sense to) shift to another water year in the middle of that simulation. This means that the weighting of a given water year, which determines how many times that year gets sampled in the several hundred simulations that are done in a study, must be the same for the fall period and the subsequent January through July period.

For the May analysis, we examined the fall and winter runoffs as a function of the runoff of the preceding January through July runoff and determined that there was a weak correlation. We are somewhat more likely to have a dry fall and winter on the heels of a dry spring and summer. We approximated this by limiting the water years that we used in the simulations to the driest two thirds (annual runoff volumes of 114 million acre feet and less) and assigned equal weights to each of the years within that group. For this analysis we attempted to have a somewhat better rationale for the weighting of the water years.

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[5] Outflows at Arrow Lake were reduced to store more water. The downstream generation that was lost as a result of the reduced outflows was made up by foregone spill.

[6] The May analysis analysed a limited set of synthetic water years spanning the anticipated range of runoff volumes for the rest of the January-July period.

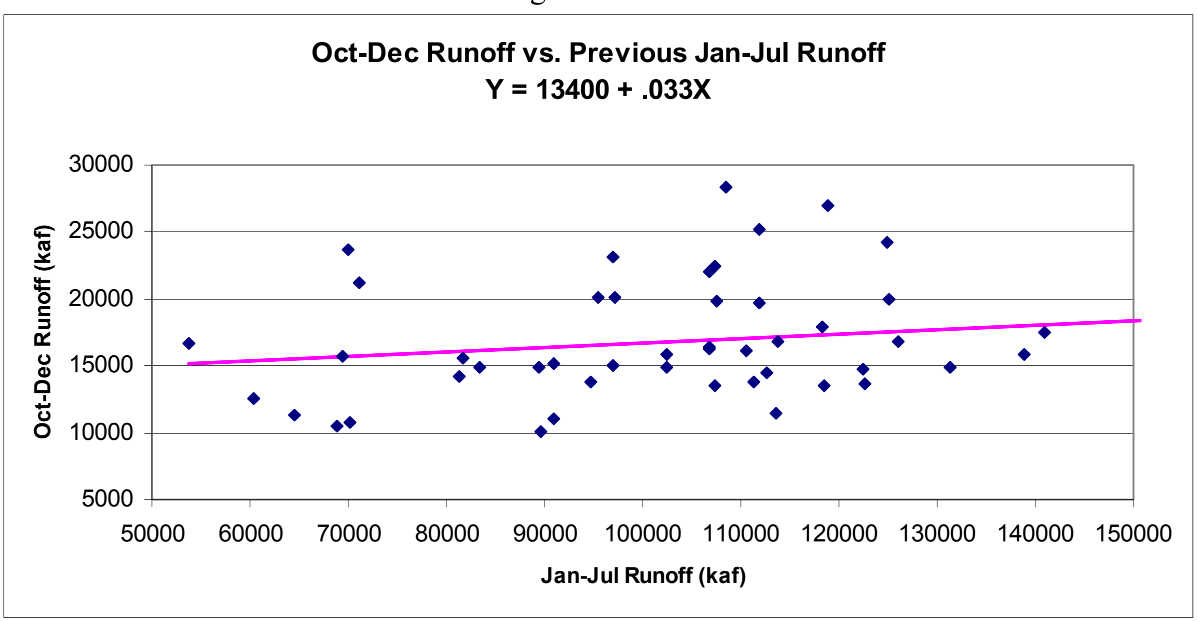
4.3 Current Runoff Estimates

Based on forecasts from the Climate Prediction Center (CPC) and using statistical information from the historical record, the Council staff has estimated both the October-through-December and the January-through-July runoff volume forecasts at The Dalles Dam. The fall runoff volume is expected to be about 15 million acre-feet (the 50-year average is 16.4) and the spring-summer runoff volume is expected to be about 94 million acre-feet (the 50-year average is 103.2). The level of uncertainty is large, with the 95-percent confidence interval estimated to be about plus or minus 30 million acre-feet for the January-through-July forecast. In comparison, Bonneville Power Administration's forecasts for the October-through-December and January-through-July runoff volumes are 13.6 and 94 million acre-feet, respectively.

4.3.1 Expected Runoff Based on Historical Record

For each of the 50 historical water records from 1929 through 1978, the relationship between the January-through-July runoff volume and the ensuing October-through-December runoff volume was plotted. This relationship is illustrated in Figure 4-1. A weak linear relationship was derived using regression analysis. The observed 2001 January-through-July volume of 58.2 million acre-feet yields a fall runoff volume forecast of about 15 million acre-feet. The same methodology was used to generate a January-through-July runoff volume forecast. Again we observe a low correlation factor. Nonetheless, proceeding with this technique yields a January-through-July runoff volume forecast of about 99 million acre-feet.

Figure 4-1



4.3.2 Expected Runoff Based on Climatological Indices

The El Nino Southern Oscillation (ENSO) and the Pacific Decadal Oscillation (PDO) are increasingly used to forecast future climate patterns and precipitation. However, the

Climate Prediction Center currently sees no clear indication that precipitation will be low, average or high, but does project that there will be higher variability in the weather.

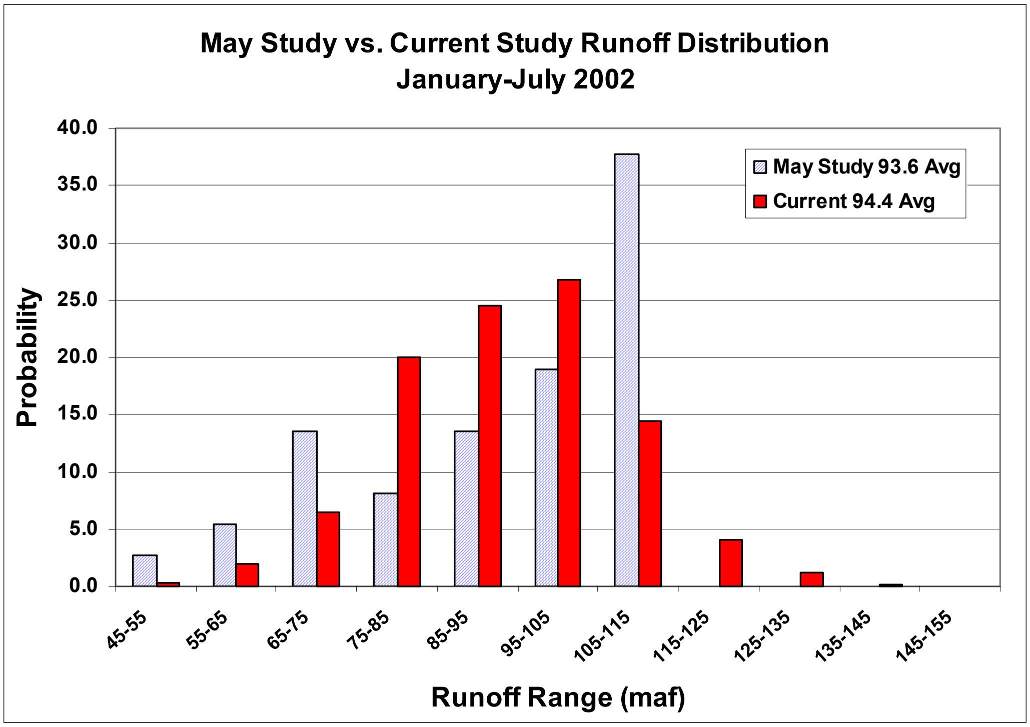
Because the Northwest's soil is dry and aquifer levels are low due to this past season's drought, some of the anticipated precipitation will be absorbed by the soil or depleted aquifers. Estimates of how much water will be absorbed are difficult to come by and will vary by location. However, rough estimates range between 10 and 20 percent, depending on the anticipated runoff volume. The historical runoff records include some soil absorption for those years following dry conditions. As a very, very rough estimate for the runoff forecast, we can assume that on average, an additional 10 percent of precipitation could potentially be absorbed because of the extremely dry conditions this year. Using this estimate yields an October-through-December forecast of 14.8 million acre-feet and a January-to-July forecast of 92.9 million acre-feet.

4.3.3 Runoff Distribution

For the January-through-July runoff, staff assumed a normal runoff volume distribution with a mean of 94 million acre-feet and a standard error of 13.8 million acre-feet. This is the standard error associated with the January runoff forecast. Each of the historical water year runoff volume values was "fit" to this curve and weights (relative frequency) for each water year were derived from this curve. These weights determine how frequently each water year is sampled in the Monte Carlo simulation. The same weightings are used for both the October-through-December and the January-through-July runoffs.

Figure 4-2 shows the current distribution for the January-July runoff compared to the distribution assumed for the May study. As can be seen in this figure, the May study distribution has a higher likelihood of drawing the driest water years, even though the average of both distributions is nearly the same. Because of the particular bias of the May study distribution toward the dry end, the loss of load probability will be higher (all else being equal).

Figure 4-2



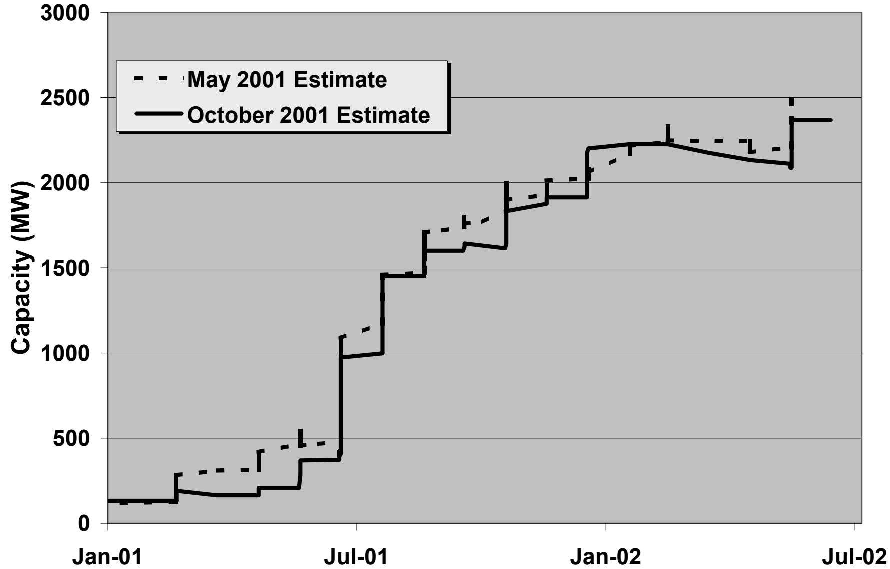
5.0 Non-hydro Generating Resource Prospects for Winter 2001-02

The year 2001 has seen substantial addition of new generating capacity in the Northwest. On net, it is expected that about 2,140 megawatts[7] of new capacity will enter service during the year. This represents a 5-percent annual increase in capacity and a 7-percent increase in energy production capability. This rate of expansion has not been experienced in the Northwest since 1984.

An even greater increase in generating capacity is expected in 2002. Little of that capacity will enter service prior to June 2002, so will not be available to support winter loads. Our current estimates of new capacity for winter 2001-02 service do not substantially differ from those used for the May 2001 assessment of reliability (Figure 5-1). For this reason, non-hydro generating capacity additions do not account for the observed changes to winter system reliability. However, as discussed in Section 8.1, the treatment of non-hydro generating unit reliability has been refined for this assessment and may account for some of the improvement in system reliability for this coming winter.

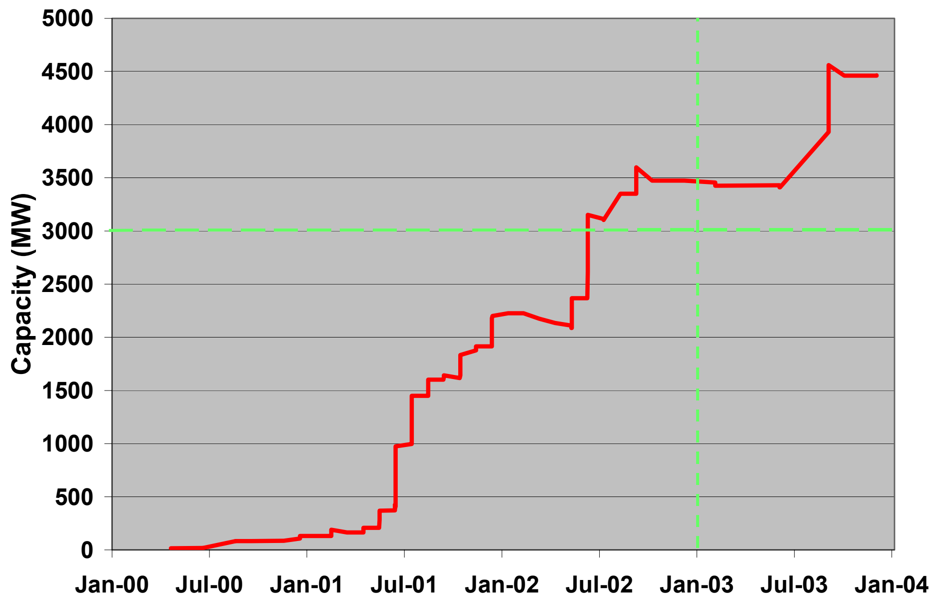
[7] Because of additional information becoming available since completion of this reliability analysis, the figures for capacity additions appearing in this report differ slightly from the values used in this reliability analysis and reported earlier. The differences are unlikely to significantly affect the findings or conclusions of the study. The figures used in the analysis are as follows: Net capacity additions during 2001 - 2180 MW; permanent component - 1650 MW; temporary component - 530 MW.

Figure 5-1 Pacific Northwest net capacity additions: October vs. May



Over the longer-term, scheduled capacity additions are expected to increase Northwest generating capacity by nearly 3,500 megawatts by January 2003 (Figure 5-2). This is 500 megawatts in excess of the 3,000 megawatts of capacity identified in the Council's March 2000 reliability assessment as needed to reestablish conventional system reliability standards by winter 2002-03. About 400 of the 3,500 megawatts, however, are wind turbines. Wind turbines are generally given a capacity credit for reliability purposes of about a third of that given dispatchable plants.

Figure 5-2: Pacific Northwest scheduled capacity additions



5.1 Permanent generation

About 1,650 megawatts of the 2,140 megawatts of net additional generation expected to be placed in service during 2001is permanent. Nearly half (46 percent) of this capacity is at two large gas-fired combined-cycle plants, Klamath Cogeneration and Rathdrum Power. These were under construction prior to the appearance of the West Coast energy crisis in June 2000. A substantial portion (23 percent) of the new permanent capacity is composed of simple-cycle gas turbines, also fired by natural gas. Most of these units are highly modular aeroderivative gas turbines requiring little construction time. Though largely initiated in response to the capacity shortages and high market prices, several of these projects are owned by utilities that intend to use them over the longer-term for firming hydropower.

Wind turbine-generators represent the third major component (17 percent) of the permanent capacity installed during 2001. Though wind development of this magnitude is new to the Northwest, most of the wind capacity entering service in 2001 was under development prior the energy crisis. High market pries undoubtedly helped drive completion of these projects; although an important factor is the pending expiration of federal incentives at the end of 2001. Other factors driving wind development include the emerging green tag market, demand for retail green power products and the low-carbon resource acquisition policies adopted by several Northwest utilities.

The availability of this permanent capacity for winter 2001-02 is reasonably certain. About 70 percent of the 1,650 megawatts has entered service, and all of the remaining capacity is under construction.

5.2 Temporary generation

From late 2000 through June 2001, approximately 1,600 megawatts of temporary generating capacity were proposed for development in the Northwest. Those proposing temporary capacity included utilities and industries exposed to market prices, independent developers holding contracts with utilities or industries exposed to market prices, and some apparently developing on a purely speculative basis.

Most temporary projects consist of clusters of reciprocating engine-generator sets or small aeroderivative gas turbines. Projects range from less than one to over 150 megawatts. Most reciprocating units operate on fuel oil, though some use natural gas. Most of the gas turbines operate on natural gas. These projects operate under temporary permits ranging from 90 days to 24 months duration.

Approximately 890 megawatts of this capacity will have been in service at some time during the year. Declining power prices are the leading reason for termination of hundreds of megawatts of planned projects and removal of nearly 400 megawatts of installed temporary capacity. Some projects were terminated or removed because of air emission and noise concerns, permit expiration or replacement by permanent generating units.

Mosttemporary generation has been idle since the decline in power prices beginning in mid-June. These projects have variable costs in the range of $90 to $125 per megawatt-hour and are not economic to operate in the current market. Based on discussions with the operators of most of the remaining temporary capacity, we anticipate that about 500 megawatts of temporary capacity will be available for service during winter 2001-02. Because these units are relatively expensive to run, they would run only in an emergency.

The ability to dispatch the remaining temporary generation under the current FERC price caps mechanism has been questioned. The operating costs of the temporary units generally exceed the current price cap, and the cap mechanism does not permit caps to be reset for reliability events outside of California. Much of the remaining temporary generation is under utility or industrial control, or is contracted to utilities. This capacity could presumably be dispatched, if needed by the controlling entity. At question is whether generation not needed by the controlling entity could be dispatched under bilateral contracts or "spark spread" agreements. For this study we assumed that all temporary generation would be available for service as needed. FERC is re-examining the issue and may have a favorable resolution before the winter.

6.0 Contract Obligations

Contract obligations are firm agreements that Northwest parties have for delivery of power to extra-regional parties or that extra-regional parties have for delivery to the Northwest. The former represent an additional load, the latter represent an additional resource. We have relatively poor information on contract obligations. The Council queried the major utilities in the region regarding their commitments. In its request, the Council included a confidentiality agreement under which the Council is obligated not to disclose individual party data and use the data only as a regional aggregate.

We received a very poor response to this query. This is largely the result of the nature of the competitive power industry. For one, it is difficult to know whether the ultimate disposition of a sale or source of a purchase is in-region or out of region, particularly if a purchaser or seller is a marketer. Secondly, there are concerns about the competitive value of such information that were apparently not satisfied by the Council's willingness to hold such data confidential. It is also true that we should have probably sought information directly from marketers operating in the region. However, the lack of responsiveness from regional entities with which the Council has had a relationship over the years does not make us believe that marketers would be anymore forthcoming.

For this analysis we have used the contract data from the most recent published Bonneville "White Book."[8] In addition, we included 200 megawatt-months of energy in January that is the return of energy to Bonneville from exchanges made with California earlier this year. We have subsequently been able to corroborate the data we used with data submitted by the control areas to the Northwest Power Pool. Our initial data appear to be very close to the Power Pool data although slightly conservative, i.e. a somewhat

[8] http://www.bpa.gov/power/pgp/whitebook/whitebook.shtml

higher level of exports. Nonetheless, we believe the lack of responsiveness of the industry is potentially a problem, if not for this particular analysis, then in the analysis of some future period when power supply adequacy is an issue.

7.0 Availability of imports

In addition to contractual obligations to deliver energy to Northwest parties, there is also the possibility of making short-term market purchases from parties in California and elsewhere in the West in the event of a period of shortfall here in the Northwest. Although this has traditionally been the case, last winter there was very little energy available from California and the Southwest. We believe this was the case because of a variety of factors surrounding the dysfunction affecting the operation of the California market that resulted in large amounts of capacity being unavailable. These factors include the fact that a number of plants had been run very hard in the summer and fall of 2000 and were shut down for maintenance during the winter, other plants had used up their allowances for emissions of nitrogen oxide and were required to shut down or face very large fines, and other plants that were shut down because their owners were concerned they would not get paid given the financial difficulties facing Southern California Edison and Pacific Gas and Electric.

While there are still issues regarding the California market, much has changed:

- Generation was not run as hard last summer with generally lower loads;
- Approximately 3,500 megawatts of new generation have come on line; and
- Approximately 3,500 megawatts less existing generation is scheduled to be out-of-service for overhaul this winter compared to last winter.

For this analysis we have used the same import assumptions used in the May analysis. We assumed that there would be up to 1,000 megawatts available during the peak period (6 AM until 10 PM) and an additional 3,000 megawatts during the off-peak period. We believe these are conservative assumptions and that more energy would be available if necessary.

8.0 Changes in Methodology

For this analysis, logic improvements were made to GENESYS in two principal areas, generation unit forced outages and transmission loop flow.

8.1 Treatment of forced outages on thermal units

GENESYS previously used an algorithm that simply sampled twice a week for unit availability states, and then held those states constant until the next sample. This produces individual outages consistent with unit forced outage rates, but overall system outage patterns that could be somewhat blocky. This logic has been replaced in the current version with a frequency and duration method for unit outages. The algorithm uses time-to-failure and time-to-repair distributions to simulate the uncertainty in both how long a unit runs before an outage occurs, and in the length of outage. The method produces a more realistic system outage pattern, allowing individual units to fail or return to service at any time step within the simulation, not just at the beginning of specific days as in the previous implementation. Similar to the original method, the frequency and duration method assumes units are either fully available or completely out of service. Though the assumed outage rates used in this assessment are equivalent (i.e., including the net effect of both full and partial outages), partial capacity outages are not currently modeled.

8.2 Treatment of transmission

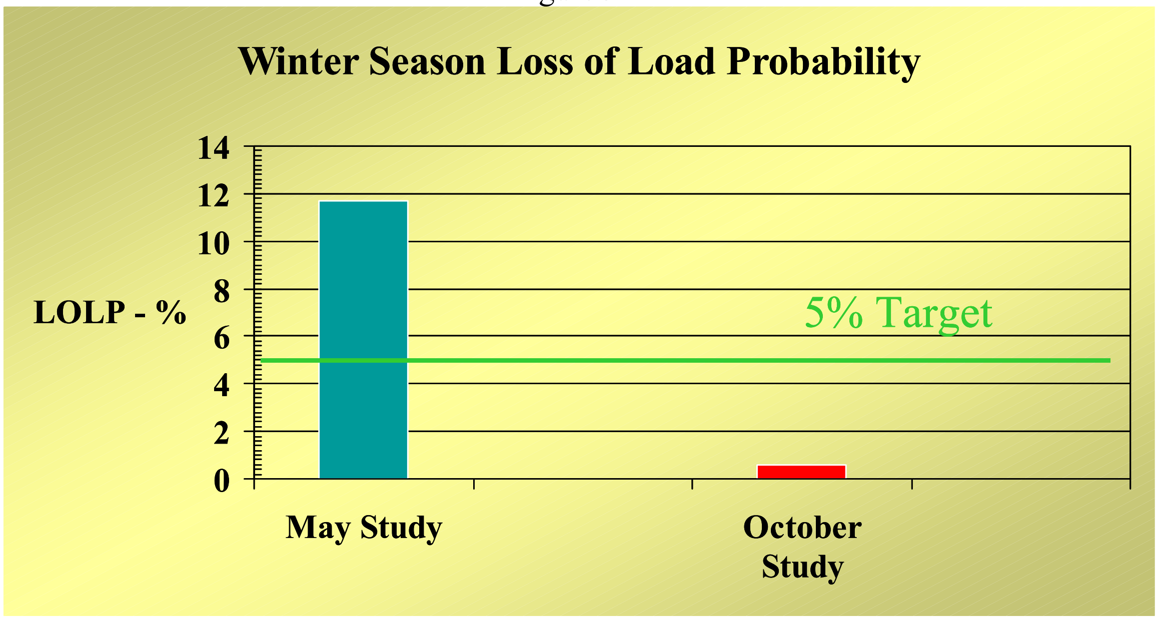
GENESYS previously ignored transmission loop flow. It would treat each transmission path and its associated constraints independently from other paths. This has the potential effect of overstating transmission capability between areas where loop flow exists. The current implementation recognizes loop flow constraints and will limit transmission capability for any node-to-node transaction by the amount that causes constraints to be reached in any of the legs comprising the loop flow path.

9.0 Results

9.1 Loss of Load Probability

The overall probability of power supply inadequacy of greater than 10 average megawatts (LOLP or loss of load probability) for the four-month winter period is shown on Figure 9-1.

Figure 9-1

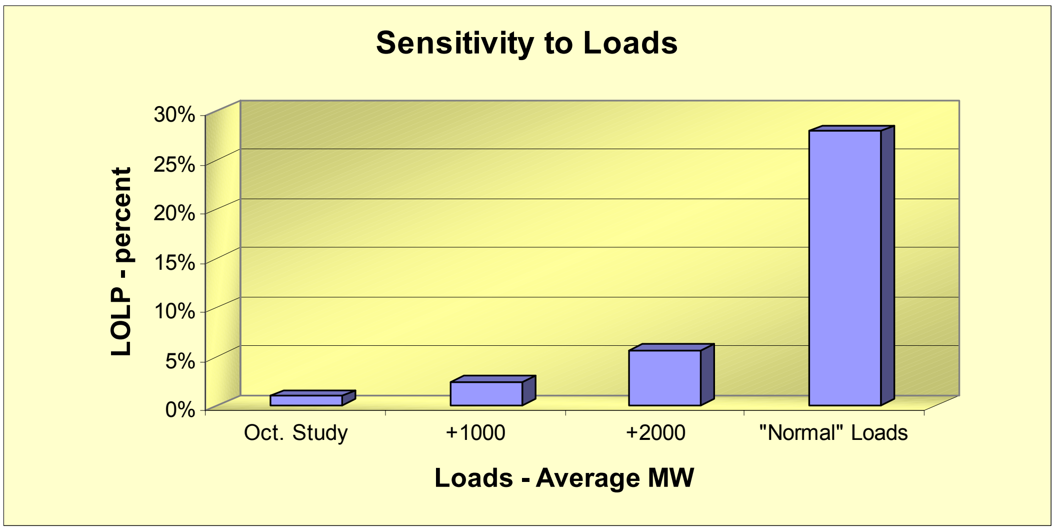


The loss of load probability is just under 1 percent compared with the almost 12 percent found in the May study and the goal of 5 percent. This does not mean that there could not be a significant problem this winter given the right combination of extreme temperatures, poor water conditions, and forced outages. But the probability of occurrence is quite small.

There are a number of factors affecting this outcome. The runoff distribution used in the current analysis does contribute to the lower loss of load probability, but its effect is small. If the same assumption were used as in the May study (using only water years with runoff volumes less than 114 million acre feet) the LOLP increases only to slightly over 1 percent. The increased energy in storage in Canada and the greater flexibility with which it could be used appears have reduced the loss of load probability by 3 to 4 percent from the May study values.

The most significant factor is the effect of loads. The sensitivity of the loss of load probability to loads is illustrated in Figure 9-2.

Figure 9-2



For this study, the basic loads used in the October analysis were incremented as shown. "Normal" loads correspond to the Council's forecast from the last power plan. These loads are approximately 4,500 to 5,000 average megawatts greater than those used in the October analysis. The loads in the May study were approximately 2,000 average megawatts over the current estimates. From this chart, the non-linearity of the loss of load probability is evident.

Leading Indicators

Although the current analysis indicates a low probability of power supply problems this winter, the probability is not zero. Combinations of poor water, extreme weather that increases loads, and forced outages could occur that could pose power supply problems. Moreover, many of the parameters that have gone into this analysis are derived from estimates or forecasts that may prove wrong. This raises the question of whether there might be "leading indicators" of potential problems that should be tracked. Given the sensitivity of the loss of load probability to loads indicated in Figure 9-2, it will be very important to track actual loads and net exports (which have the same effect) through the fall and winter. If these appear to be diverging significantly from the forecast used in this analysis, there may be cause for concern.

Weather is always an issue in that high loads are driven by extreme weather. For every degree decrease in the regional average temperature, loads go up by approximately 300 megawatts. The industry tracks weather carefully. Forecasts of severe weather events can provide a few days in which to prepare short-term operational responses.

Water conditions are more difficult to predict. In the analysis, we can determine under what water conditions we observed problems. However, we will not know except within a very wide range what water conditions we are actually going to have. Staff is in the process of looking the level of unserved load observed in the simulations on a weekly basis as a function of streamflows and average temperatures for the week. This is being done for both the base case and a case where the loads are 2000 megawatts over the base case loads. This information, given a week-ahead forecast of streamflows and temperatures, would give an indication of the likelihood of supply problems in that week.

9.2 April Reservoir Contents

One objective of the 2000 Biological Opinion is to achieve reservoir levels at their flood control elevations by early April. This is to assure adequate water for flow augmentation during the spring migration season. However, the Biological Opinion recognizes that it is not always possible to reach the flood control levels. Consequently, it aims for achieving a relatively high probability of reaching flood control over the historic range of water conditions. The targeted probabilities are 85 percent at Grand Coulee and 75 percent at Hungry Horse and Libby reservoirs.

One factor that can affect the likelihood of refill to flood control is the use of "hydro flexibility." Hydro flexibility is the ability to draft reservoirs below their normal drafting limits during emergency situations, such as cold snaps or the loss of a major resource. Generally these situations only last a few days, after which the drafted water is replaced by running surplus Northwest resources or by importing energy from outside the region. When the Northwest power supply is adequate, replacing hydro flex water is typically not a problem. However, if the system is not adequate, emergency drafts cannot always be refilled in time for the spring fish migration season. This leaves less water in reservoirs for flow augmentation and can affect the survival of juvenile salmon and steelhead.

The current analysis uses hydro flexibility to the extent necessary to accommodate periods of high loads and/or reduced non-hydro resources. The Council's estimate for this winter's loss of load probability is under 1 percent, given the current demand and resource forecasts. However, the use of hydro flexibility is essential to maintaining a reliable power system. Curtailing the use of emergency drafts raises the loss of load probability to about 16 percent.

To assess the impact of the use of hydro flexibility on the probability of reaching flood control reservoir levels by April 15, refill probabilities were analyzed both without and with the use of hydro flexibility. This year, expected runoff volumes are forecast to be slightly less than average for both the fall and spring seasons. US reservoirs are about where they should be for this time of year but the Canadian reservoirs are at lower-than-desired elevations. This will likely reduce inflows into the U.S. sometime between now and the end of next summer.

As a consequence, the probabilities of reaching flood control elevations are about 61 percent at Grand Coulee and about 40 percent at Hungry Horse and Libby, even without the use of hydro flexibility. Using hydro flexibility in emergency situations does not significantly affect these probabilities. The forecast load and resource situation is such that it is possible to replace the water used during the emergency draft by running thermal generation and using imports. These probabilities are consistent with the language in the Biological Opinion. Under normal conditions and a full range of expected runoff volumes, the resulting probabilities should be at or very close to the targeted levels.

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