Appendix L: Climate Change and Power Planning

SUMMARY OF KEY FINDINGS

Climate change presents a daunting challenge for regional power planners. There are at least two ways in which climate can affect the power plan. First, warming trends will alter electricity demand and change precipitation patterns, river flows and hydroelectric generation. Second, policies enacted to reduce green house gases will affect future resource choices. There remains a great deal of uncertainty surrounding both of these issues. While the physical impacts of climate change cannot be modeled with precision for the Pacific Northwest, it is possible to make general predictions about potential changes and, as a result, recommend policies and actions that could be adopted and implemented to prepare for potential future impacts. This appendix describes the first of these issues, namely how climate change may affect demand for electricity and production of hydroelectric generation.

Global climate change models all seem to agree that future temperatures will be higher but they disagree somewhat on levels of precipitation. Some models suggest that the Northwest will be drier while others indicate more precipitation in the long term. But all the models predict less snow and more rain during winter months, resulting in a smaller spring snowpack. Winter electricity demands would decrease with warmer temperatures, easing the Northwest's peak requirements. In the summer, demands driven by air conditioning and irrigation loads would rise and potentially force the region to compete with the Southwest for electricity resources.

All of these changes have implications for the region's major river system, the Columbia and its tributaries. More winter rain would result in higher winter river flows. Less snow means a smaller spring runoff volume, resulting in lower flows during summer months. This could lead to many potential impacts, such as:

- Putting greater flood control pressure on storage reservoirs and increasing the risk of late fall or winter flooding;

- Boosting winter production of hydropower when Northwest demands are likely to drop due to higher average temperatures;

- Reducing the size of the spring runoff and shifting its peak to earlier periods in the year;
- Reducing late spring and summer river flows and potentially causing average water temperatures to rise, especially in the tributaries;
- Jeopardizing fish survival, particularly salmon and steelhead, by reducing the ability of the river system to meet minimum flow and water temperature requirements during spring, summer and fall migration and spawning periods;
- Reducing the ability of reservoirs to meet demands for irrigation water;
- Reducing summer power generation at hydroelectric dams when Northwest demands and power market values are likely to grow due to higher air conditioning needs in the Northwest and Southwest; and
- Affecting summer and fall recreation activities.

The potential effects of climate change on river flows and the operation of the hydroelectric system are still being refined but indications are that the region will see a slowly evolving shift in flow pattern. Analysis summarized in this appendix identifies the potential range of changes and the corresponding impacts to hydroelectric production. Some suggestions are made regarding actions that could be implemented to mitigate potential impacts to reliability and potential increases to fish mortality. However, due to the uncertainty surrounding the data and models used for climate change assessment, no actions (other than to continuing to monitor the research) are recommended in the near term.

The effects of the uncertainty surrounding a potential carbon penalty and other climate policies have been incorporated into the Councils portfolio analysis and have appropriately influenced the recommended resource strategy and action plan. Further details of that analysis are provided in Chapter 11 of the power plan.

BACKGROUND

Dozens of groups around the world are actively investigating global climate change and its potential impacts.[1] Most of these organizations have developed complex computer models used to forecast long-term changes in the Earth's climate. These models are used primarily to estimate the effect of greenhouse gases on temperature and precipitation. The most sophisticated of these models are known as "general circulation models" or GCMs. They take into account the interaction of the atmosphere, oceans and land surfaces.[2] Each of these models has been "calibrated" to some degree and crosschecked against other such models to give us more confidence in their forecasting ability.

Scientists are confident about their projections of climate change for large-scale areas but are less confident about projections for small-scale areas. This is largely because computer models used to forecast global climate change are still ill equipped to simulate how things may change at smaller scales. Forecasts on a global level are of little use to planners in the Northwest. Thus, a

[1] http://stommel.tamu.edu/~baum/climate_modeling.html
[2] http://gcrio.org/CONSEQUENCES/fall95/mod.html

method of "downscaling" the output from these models has been developed.[3] This downscaled data matches better with hydrological data used to simulate the operation of the Columbia River Hydroelectric Power System. By using temperature and precipitation changes forecast by global climate models but downscaled for the Northwest, an adjusted set of potential future water conditions and temperatures can be generated. The adjusted water conditions can be used as input for power system simulation models, which can determine impacts of climate change to the Northwest hydroelectric power system. Temperature changes lead to adjustments in electricity demand forecasts.

There are at least 20 different global models that simulate future changes in temperature and precipitation. Every one of these models, to varying degrees, projects a warming trend for the Earth. Each uses modern mathematical techniques to simulate changes in temperature as a function of atmospheric and other conditions. Like all fields of scientific study, however, there are uncertainties associated with assessing the question of global warming and, as we are often reminded, a computer model is only as good as its input assumptions. The effects of weather (in particular precipitation) and ocean conditions are still not well known and are often inadequately represented in climate models -- although all play a major role in determining our climate.

TEMPERATURE AND HYDROLOGICAL CHANGES

For the Northwest, models show that potential impacts of climate change include a shift in the timing and perhaps the quantity of precipitation. They also show less snow in the winter and more rain, thus increasing natural river flows. Also, with warmer temperatures, the snowpack is projected to melt earlier, which would result in lower summer river flows. More discussion regarding these possible impacts and their implications is provided in the next section.

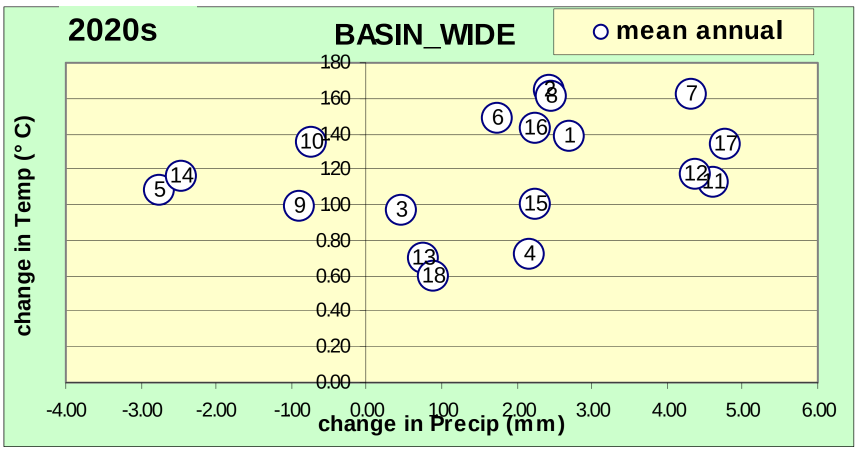
Preliminary downscaled hydrologic and temperature data for the Northwest was obtained from the Joint Institute for the Study of Atmosphere and Ocean (JISAO)[4] Climate Impacts Group (CIG)[5] at the University of Washington. This preliminary data is for a single climate change scenario, which is a composite of results from several climate models used by the CIG and roughly represents an "expected" or average forecast. Results and conclusions provided in this appendix reflect this preliminary composite data set.

The CIG has developed an improved set of data that incorporates a more detailed geographical scale and a wider range of scenarios but unfortunately, it is not yet available in a form that can be used in Council planning models. The CIG is currently adapting results from several of its climate scenarios for use by Council and Bonneville models. The expectation is that a representative subset of scenarios will be modified for Council analysis over the next year or so. This subset of scenarios should adequately represent the full range of projections from all 20 climate models used by the CIG.

[3] Wood, A.W., Leung, L. R., Sridhar, V., Lettenmaier, Dennis P., no date: "Hydrologic implications of dynamical and statistical approaches to downscaling climate model surface temperature and precipitation fields."
[4] http://tao.atmos.washington.edu/main.html
[5] http://tao.atmos.washington.edu/PNWimpacts/index.html

A summary of forecasted annual temperature and precipitation changes from the 20 global climate models used by the CIG (for the 2020 time period) is shown in Figure L-1. In this figure, the X-axis represents change from current conditions in annual precipitation (in millimeters) and the Y-axis represents change in annual temperature (in degrees Centigrade). Each point in this figure represents the average precipitation and temperature change for each climate change scenario studied by the CIG. For example, the point labeled number 3 indicates that for the CIG climate scenario number 3, the average annual precipitation is forecast to be about 0.5 millimeters greater and the average annual temperature is forecast to be about 1 degree Centigrade greater. Three conclusions can be drawn from the results in this figure; 1) each model shows a net temperature increase, 2) most but certainly not all models show a slight increase in annual precipitation, and 3) there is great variation in both the temperature and precipitation forecasts.

Figure L-1: Columbia Basin Temperature and Precipitation Change Forecasts[6]



Unfortunately, the detailed hydrologic data required to run the Council's hydroelectric simulation model was not available for any of the scenarios plotted in Figure L-1. Consequently, analysis in this appendix is based on a preliminary CIG climate change scenario, whose temperature and precipitation changes fall "somewhere in the middle of the pack" according to their staff. The other unfortunate thing about this scenario is that it was developed for the 2040s period, which is beyond the scope of this power plan's study horizon (2030). The temperature and streamflow changes forecast in this scenario were assumed to occur in 2045 and were then interpolated back into the 2010 to 2030 study horizon period. Thus, the analysis in this appendix is presented only as a preliminary assessment of potential impacts to river flows, hydroelectric generation and cost.

Other caveats regarding the analysis in this appendix are specified below:

- Climate-change adjusted stream flows were based on a 69-year water record (1930 to 1998) instead of the 70-year record (1929 to 1998).

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[6] Taken from the River Management Joint Operation Committee's preliminary summary of the University of Washington Climate Impacts Group's Global Climate Model analyses for the Northwest (RMJOC_Task1.2_ExploreScenariosSpread_v2.xls).

- No correlation was assumed between temperature increases and river flows, that is, only a single monthly temperature increase was assumed for each water condition.

- Operating guidelines (rule curves) for the hydroelectric system were not adjusted (i.e. flood control was not adjusted for the change in spring runoff forecast nor were firm drafting limits re-optimized).

- Each water condition was given an equal likelihood of occurring.

Precipitation, Snow Pack, and River Flows

Most global climate models indicate that the Northwest will become hotter across each month of the year. If this is true, then less precipitation will fall as snow in fall and winter months, thus reducing the amount of snowpack in the mountains. More rain in winter months means higher stream flows during those months. However, with a smaller snowpack, the spring runoff will correspondingly be less, translating into lower river flows in summer. In addition, the peak of the spring runoff is projected to occur as much as a month earlier. Figure L-2 shows monthly average river flows at The Dalles Dam based on the historical record and the effect of climate change to those flows. Figure L-3 highlights the impact by plotting the change in average flow at The Dalles Dam by month.

While these changes are drastic (i.e. a flow reduction of over 100,000 cubic feet per second in June) they are not expected to occur until 2045. As will be demonstrated in a later section, annual changes to temperature and consequently river flows from today through 2045 are expected to grow gradually and in a non-linear fashion (changes growing more rapidly later in the period). In fact, climate induced changes to annual river flow in the near term are difficult to detect due to the large natural variance in annual weather patterns. The effect on regulated flows for the year 2030 is provided in Figure L-8 below, in the section entitled "Impacts to the Power System."

Figure L-2: Average Unregulated Flow at The Dalles (2045)

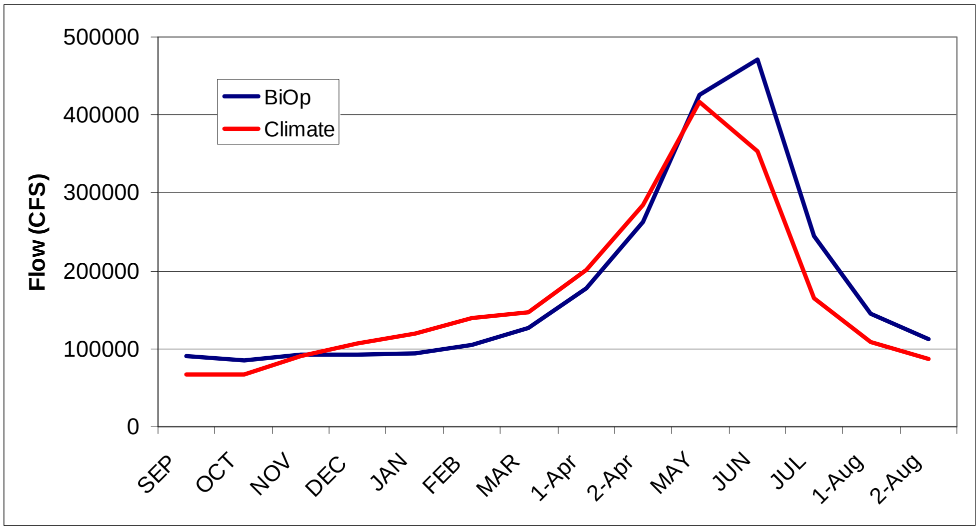
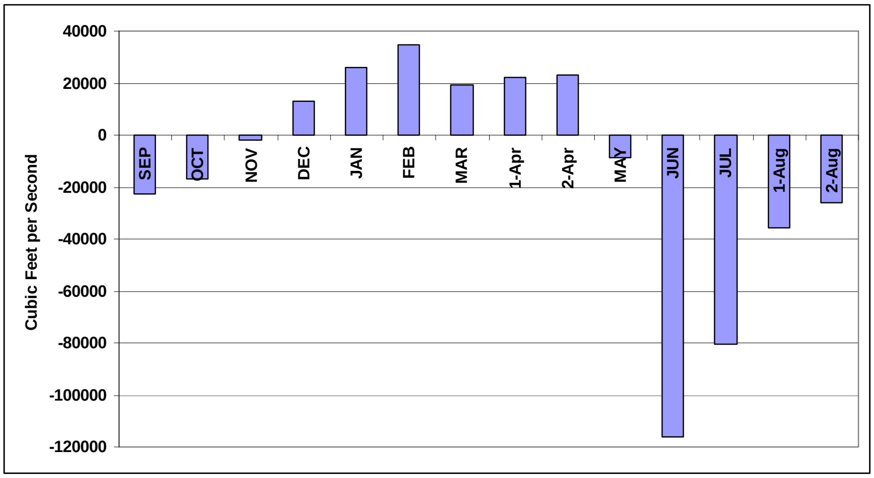


Figure L-3: Forecast Change in Unregulated Flow at The Dalles (2045)



Electricity Demand

There is a clear relationship between temperature and electricity demand. For electrically heated homes, as the temperature drops in winter months, electricity use goes up. Even for non-electrically heated homes, electricity use in winter tends to increase due to shorter daylight hours. Based on data from the Northwest Power Pool, for each degree Fahrenheit the temperature drops from normal, electricity demand increases by about 300 megawatts. This value has stayed fairly consistent over the past several years, in spite of the fact that a smaller percent of new homes are being built with electric heat. If this relationship holds true, then a two-degree increase in average temperature over winter months should translate into about a 600-megawatt decrease in electricity demand.

However, the Council does not rely on the Power Pool to estimate fluctuation in demand caused by temperature changes. The Council uses a recently developed load model to assess demand variations as a function of temperature. Results of that relationship are presented in Figures L-4 and L-5. Results from the Council's model show that a two-degree increase in the average monthly temperature for December results in about a 600 average-megawatt decrease in regional load – essentially the same conclusion that the Power Pool would make. However, that relationship doesn't hold up in January, when a two-degree increase in temperature yields just over a 400 average-megawatt decrease in load.

It should be noted that the Power Pool's rule-of-thumb temperature/load relationship is primarily focused on peak hourly loads and not on monthly average loads. For an average *monthly* increase in temperature of two degrees in winter months, the associated average *peak hourly* temperature will be higher. From Figure L-4, a two-degree increase in monthly temperature for December yields a peak hourly load decrease of just over 1,000 megawatts. If the Power Pool's relationship holds, this means that the average change in the peak hour temperature should be a little over three degrees.

Summer loads appear to be a little more sensitive to temperature than winter loads. Again using the results plotted in Figures L-4 and L-5, a slightly lower than three degree increase in the average July temperature (see Figure L-7) results in an average monthly load increase of over 1,000 average megawatts and a peak hour load increase of nearly 3,000 megawatts.

Figure L-4: Impact of an Annual 2-Degree Temperature Increase on Peak Loads

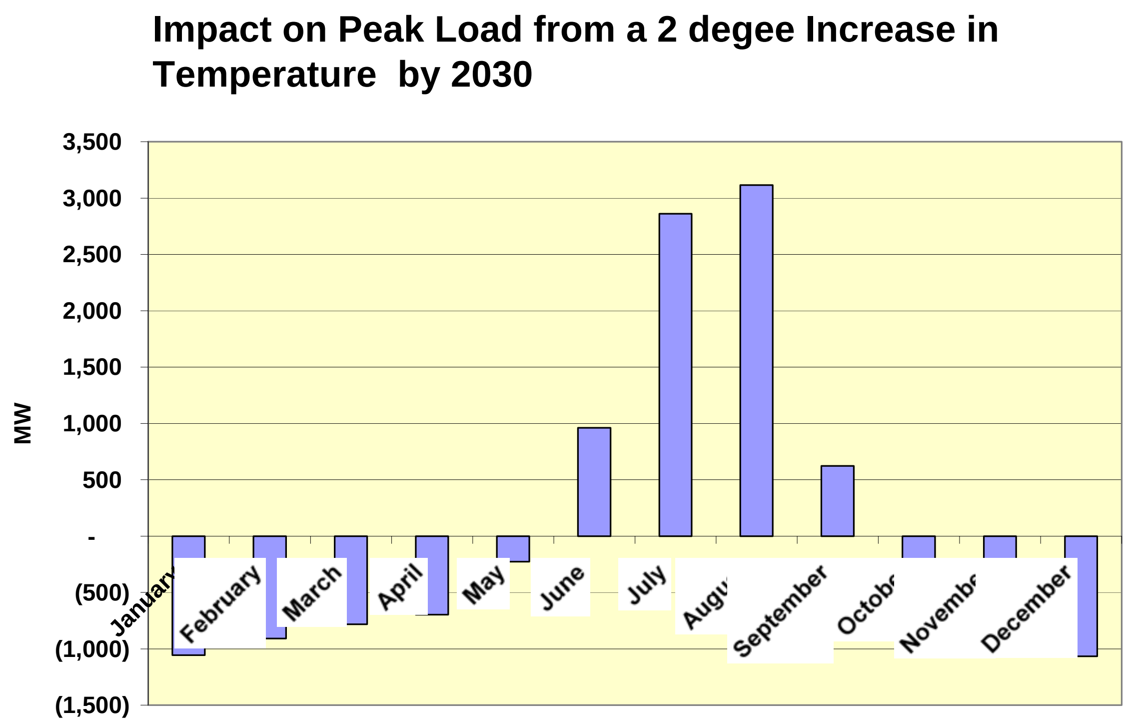
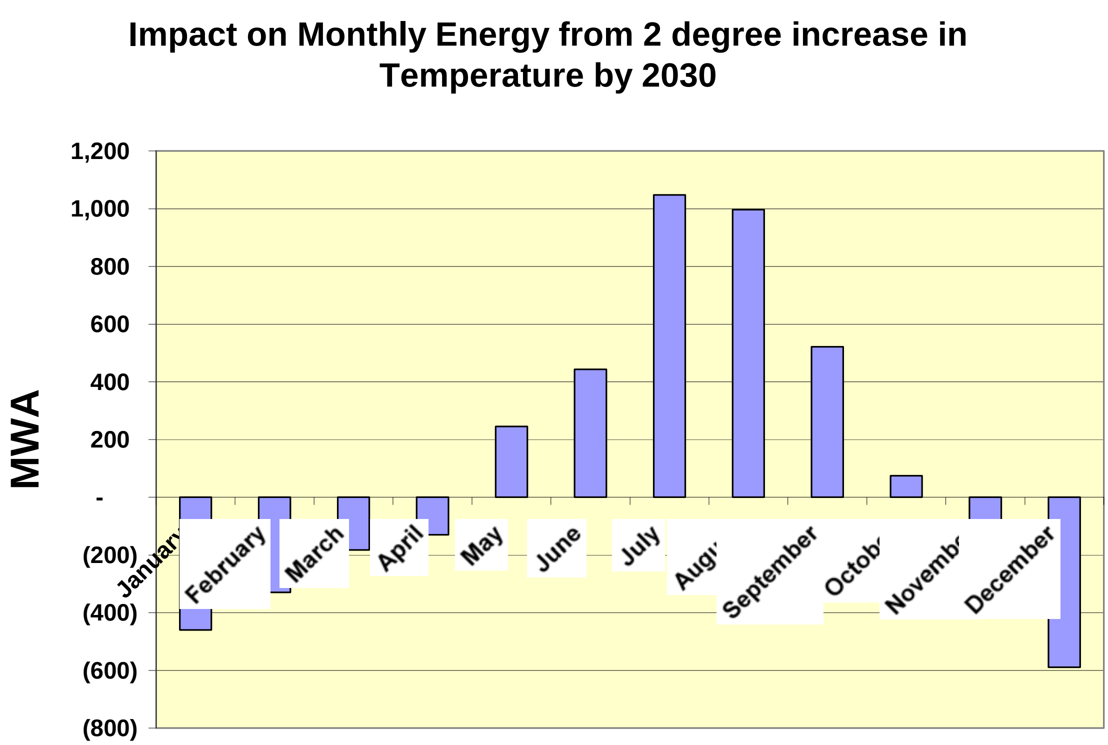
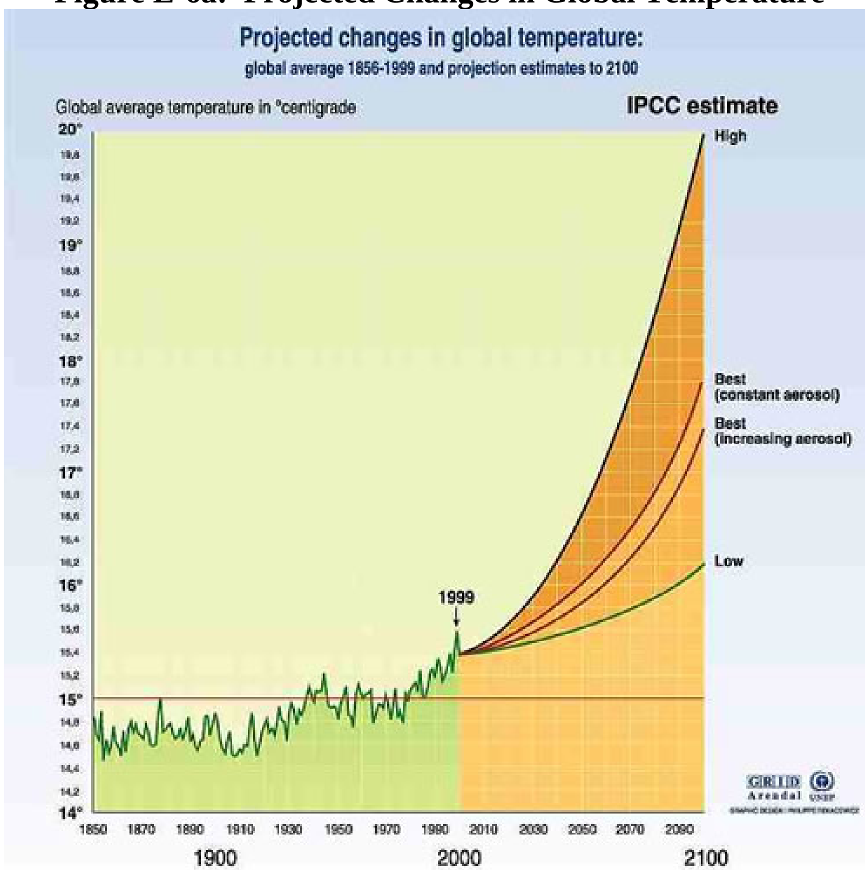


Figure L-5: Impact of an Annual 2-Degree Temperature Increase on Monthly Loads



Using preliminary data from the University of Washington, the projected increase in annual temperature caused by climate change was interpolated to be about 2 degrees Fahrenheit by 2030. However, this forecast temperature increase is not expected to grow linearly. Based on current data used in global climate models, it appears that climate induced temperature increases should grow gradually, as illustrated in Figure L-6a. This general trend for global temperature increase was used to derive a projected annual temperature change for the Northwest. Those results are shown in Figure L-6b. In addition, annual temperature increases are not distributed uniformly across each month of the year. Figure L-7 shows the monthly distribution of temperature change for an annual increase of 2 degrees.

Figure L-6a: Projected Changes in Global Temperature



Actual global temperatures are plotted on the graph for years 1856-1999 and IPCC estimates of temperature are plotted for years 1999-2100. Different lines on the graph between 1999 and 2100 indicate high, low, and best estimates of future temperature.

Courtesy GRIDA/UNEP

Figure L-6b: Projected Climate Induced Annual Temperature Change through 2030

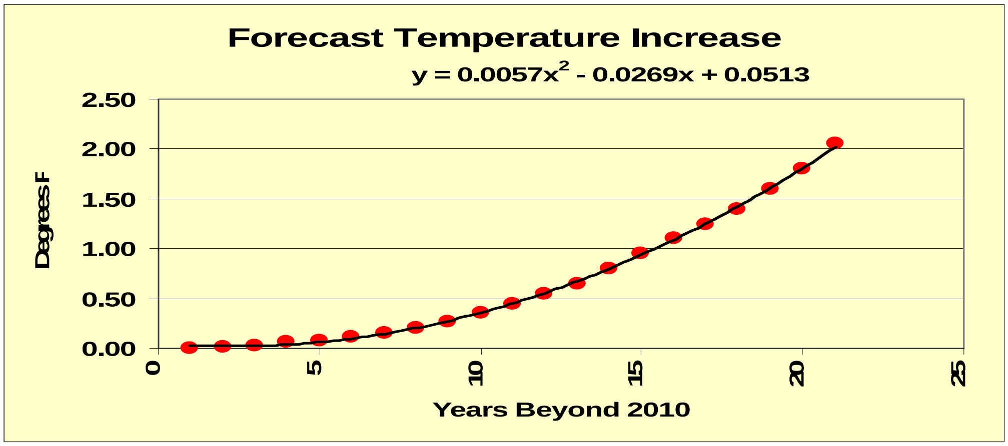
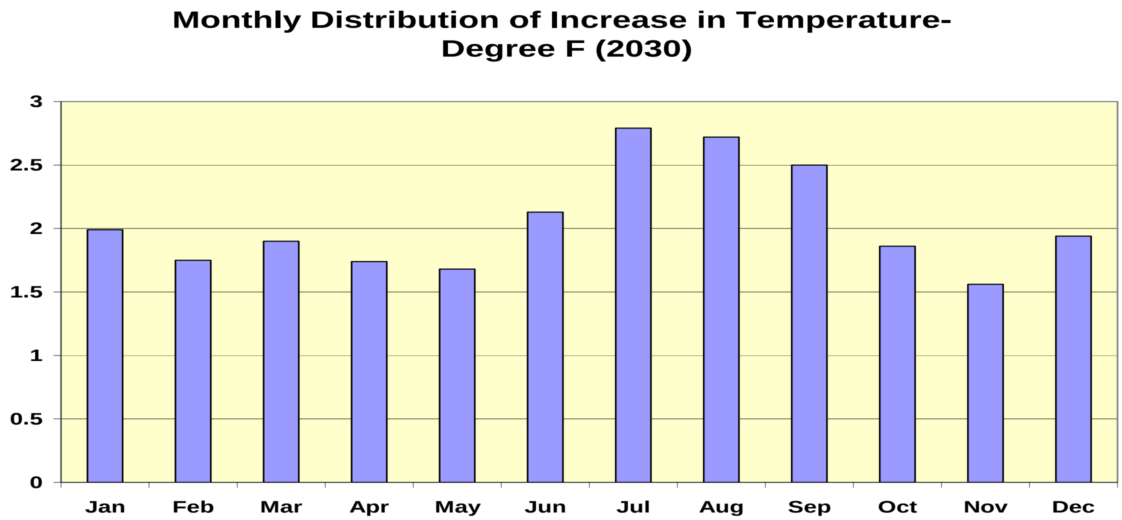


Figure L-7: Projected Changes in Monthly Average Temperatures by 2030



The projected increases in annual and monthly temperatures are converted to cooling and reduced heating degree days for each state. The cooling and heating degree days are measured as the average of annual cooling or heating degrees days for years 1985 through 2007. The cooling and heating degree days vary by state. For example, under normal conditions, the annual cooling degree day value for state of Idaho is about 531 degrees. In the preliminary climate change scenario, the normal cooling degree days is forecast to increase to 904 degrees by 2030. Each state's normal and 2030 forecast cooling and heating degree day values are shown in Table L-1 below. The summer cooling degree days is projected to increase at an average annual rate of 1.6 percent and the winter heating degree days is declining at an average annual rate of -0.3 percent.

Table L-1: Cooling/Heating Degree Days by State

	Cooling Degree Days (Normal) (1985-2007)	Cooling Degree Days (2030)	Heating Degree Days (Normal) (1985-2007)	Heating Degree Days (2030)
ID	531	904	6589	5788
MT	290	500	7826	6875
OR	271	468	4927	4328
WA	221	381	5277	4635

As a result of climate induced increases in temperatures, the annual demand for energy is forecast to increase by 120 average megawatts by 2030. However, that conclusion is somewhat misleading since the resulting January and December load is expected to decrease on the order of 400 to 600 average megawatts, while the July and August load is expected to increase by about 1,000 average megawatts for each month.

Regional summer peak load is projected to increase by over 3,000 megawatts by 2030, while the winter peak load is expected to decline by about 1,000 megawatts. The impact of temperature on summer and winter loads, especially peak hourly loads, is not equivalent because of the assumed penetration rate of air-conditioning and space heating. Air-conditioning penetration rates continue to increase over time, while the penetration rate of space heating is already at 100 percent.

Power planners have rarely had to concern themselves with summer problems because the Northwest has historically not been a summer peaking region and because of the great capacity of the hydroelectric system. Based on current assessments of power supply adequacy (Chapter 14), the existing power system can adequately serve additional climate induced demand but only in the near term. With continued demand growth, especially in summer, and increasing operating constraints on the hydroelectric system, it appears that by 2013 the region may be faced with an inadequate summer supply. Adding conservation and wind resources, as proposed by this power plan, extends the period of adequacy for the region and will give planners more time to assess climate impacts and actions to mitigate for them.

IMPACTS TO THE POWER SYSTEM

Methodology

To assess climate change impacts to the power system, the Council used two computer models. The first, GENESYS, simulates the physical operation of the hydroelectric and thermal resources in the Northwest. The second, AURORA©, forecasts electricity prices based on demand and resource supply in the West.

The GENESYS[7] computer model is a Monte Carlo program that simulates the operation of the Northwest's power system. It performs an economic dispatch of resources to serve regional demand. It assumes that surplus Northwest energy may be sold out-of-region, if electricity prices are favorable. And, conversely, it will import out-of-region energy to maintain service to firm demands.

[7] See www.nwcouncil.org/GENESYS

The model splits the Northwest region into eastern and western portions to capture the possible effects of cross-Cascade transmission limits. Inter-regional transmission is also simulated, with adjustments to intertie capacities, whenever appropriate, as a function of line loading. Outages on the cross-Cascade and inter-regional transmission lines are not modeled.

The important stochastic variables are stream flows, temperatures (as they affect electricity loads) and forced outages on thermal generating units. The model typically runs hundreds of simulations for one or more calendar years. For each simulated future year, it samples a particular runoff condition, a set of daily temperatures and the availability of thermal generating units, all according to their assumed likelihood of occurrence.

The model also adjusts the availability of northern California imports based on temperatures in that region. Non-hydro resources and contractual commitments for import or export are part of the GENESYS input database, as are forecasted prices, costs and escalation rates.

Key outputs from the model include reservoir elevations, regulated river flows and hydroelectric generation. The model also keeps track of reserve margin violations and curtailments to service. Physical impacts of climate change are presented as changes in elevations and *regulated* flows due to the adjusted *natural* flows discussed earlier. Economic impacts are calculated by multiplying the change in hydroelectric generation with the forecasted monthly average electricity price.

Hydroelectric Generation and Cost

More rain in winter months means higher stream flows at a time when electricity demand is highest. This in combination with the fact that demand for electricity is likely to decrease due to warmer winter months, should ease the pressure on the hydroelectric system to meet winter electricity needs. In fact, excess water (water than cannot be stored) may be used to generate electricity that will displace higher-cost thermal resources or be sold to out-of-region buyers.

While the winter outlook appears to be better from a power system perspective, a more serious look at flood control operations is warranted. Some global climate models indicate not only more fall and winter precipitation in the Northwest but also a higher possibility of extreme weather events, including heavy rain. This should prompt the Corps of Engineers to examine the potential to reexamine flood control evacuations prior to January, when they currently begin. Evacuation of water stored in reservoirs during winter months for flood control purposes will add to hydroelectric generation and further reduce the need for thermal generation during that time.

However, any winter power benefits could be offset by summer problems. With a smaller snowpack, the spring runoff will correspondingly be less, translating into lower river flows. As mentioned earlier, lower flows (and less hydroelectric generation) may not be a Northwest problem now because of the excess hydroelectric system capacity. Except for some small portions of the Northwest, the region experiences its highest demand for electricity during winter months. However, as summer temperatures increase so will electricity demand due to anticipated increases in air-conditioning use. In addition, potentially growing constraints placed on the hydroelectric system for fish and wildlife benefits may further reduce summer peaking capability. It is also possible that summer air-quality constraints may be placed on Northwest fossil-fuel burning resources, which would also decrease the peaking capability. The projected increase in Northwest summer demand along with potential reductions in hydroelectric generation will force the Northwest to consider resource options for summer needs sooner rather than later.

Figure L-8 shows the expected average *regulated* flow changes in 2030 due to climate impacts. This chart shows a similar pattern to that in Figure L-3, which shows the expected differences in *natural* (or unregulated) flows for 2045. Hydroelectric generation is proportional to river flow, thus it is no surprise that the average change in hydroelectric generation for 2030 (as shown in Figure L-9) has the same monthly shape.

It should be noted that this analysis was performed without modifications to operating rule curves, such as those for flood control. The effect of this is to exaggerate projected flow reductions in summer. Because future snow packs are forecast to be smaller, using current flood control elevations in the climate change scenario will evacuate reservoirs to a greater degree than necessary. Thus, reservoirs in that scenario are emptier by the end of June. Had flood control elevations been adjusted, end-of-June elevations should have remained unchanged from the base case.

Because our analysis did not adjust flood control rule curves, the projected summer flow reductions in Figure L-8 are overestimated. The magnitude of the error for summer flow changes can be approximated by assuming that the difference in the end-of-June reservoir content is released uniformly over the summer months in the climate scenario. Making this adjustment decreases summer flow reductions by about 10 percent. It should be noted that forecast changes in generation, as shown in Figure L-9, and in cost, as shown in Figure L-14, also do not reflect this adjustment.

The effects of climate change on flood control and other rule curves is currently being addressed by the River Management Joint Operating Committee (RMJOC), which is discussed in more detail later in this appendix, in the section entitled “Modeling Climate Change as a Random Variable.”

Figure L-8: Projected Regulated Flow Changes at The Dalles Dam (2030)

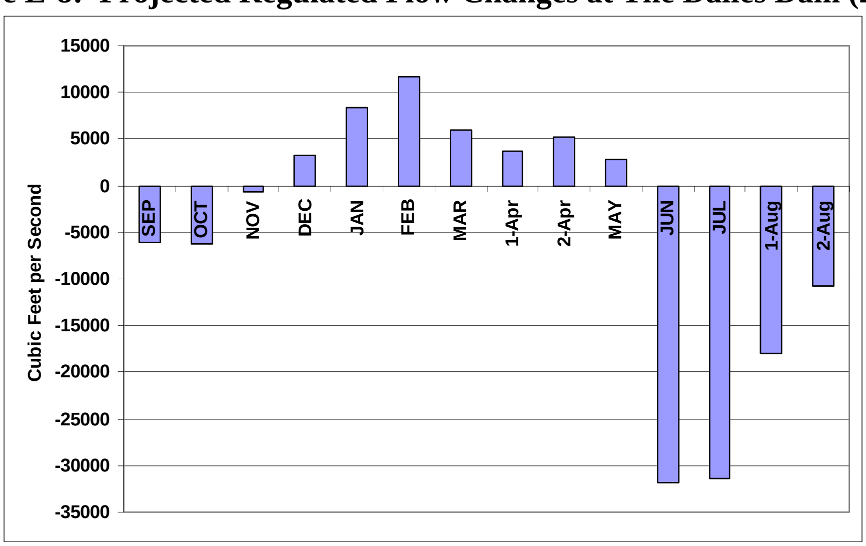
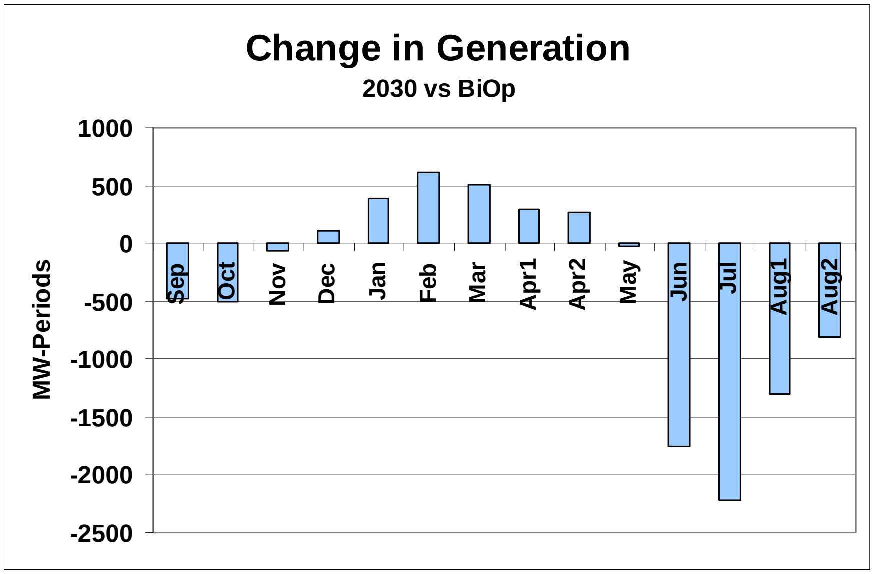
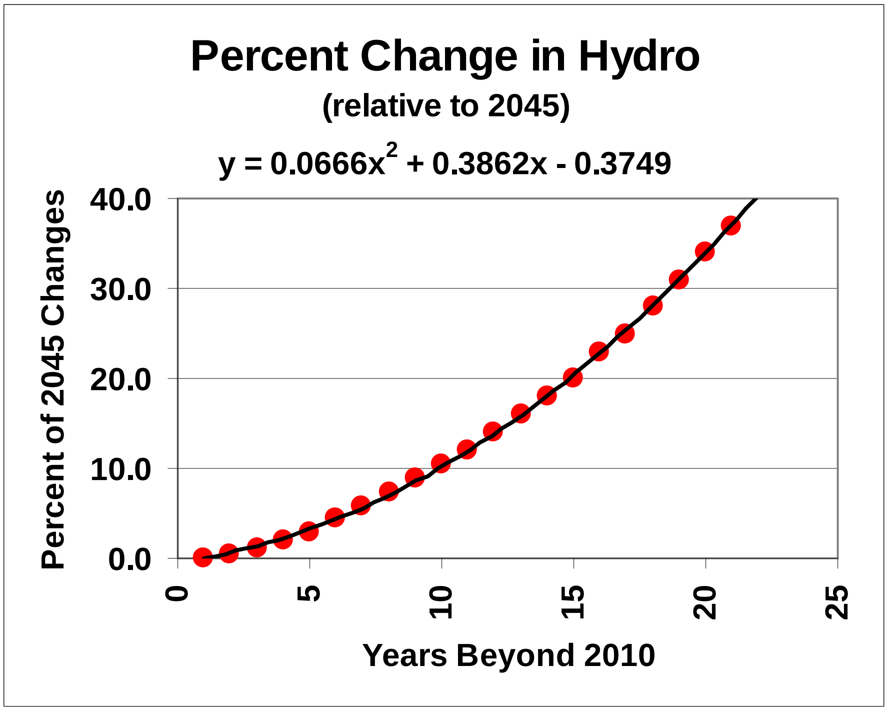


Figure L-9: Change in Hydroelectric Generation for 2030



As with projected temperature increases over time, river flow changes will also occur gradually. Figure L-10 illustrates the assumed changes to hydroelectric generation through 2030. It should be emphasized that the curve in Figure L-10 does not imply that hydroelectric generation will grow over time. What it does reflect is that portion of the 2045 change in generation that is expected in the years between 2010 and 2030. Climate change data that was actually analyzed was for the year 2045 and included the natural flow adjustments (as illustrated in Figure L-2). As with the temperature changes over time, an assumption was made that natural flow changes (and thus hydroelectric generation changes) would occur gradually. The generation changes in question are similar to those shown in Figure L-9 but reflect values for the year 2045. Figure L-10 indicates what percent of the 2045 change occurs in any given year, whether the (monthly) change is positive or negative. In fact, the data for Figure L-9 was derived by taking the average monthly generation changes for 2045 and applying a factor of about 37 percent (the value in Figure L-10 for year 2030).

Figure L-10: Projected Annual Hydroelectric Generation Change Relative to 2045



Using the above mentioned assumption regarding climate change impacts to hydroelectric generation, we derive the data for Figures L-11 and L-12. Those figures show the expected change in average hydroelectric generation for July and February over the study horizon period. By 2030, average February generation is expected to increase by about 600 average megawatts or about 4 percent. July generation is expected to decrease by about 2,200 average megawatts or about 17 percent.

Figure L-11: Average Winter and Summer Hydroelectric Generation Change

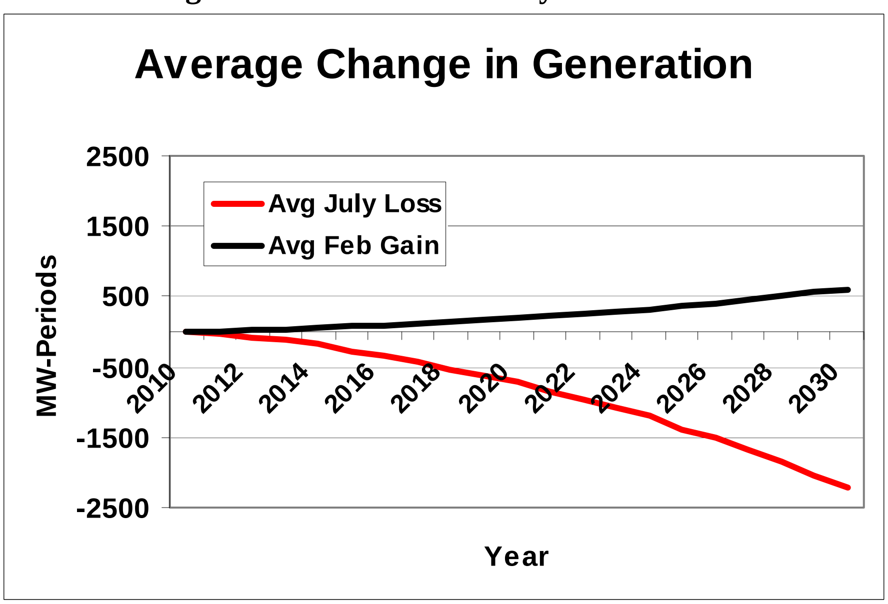
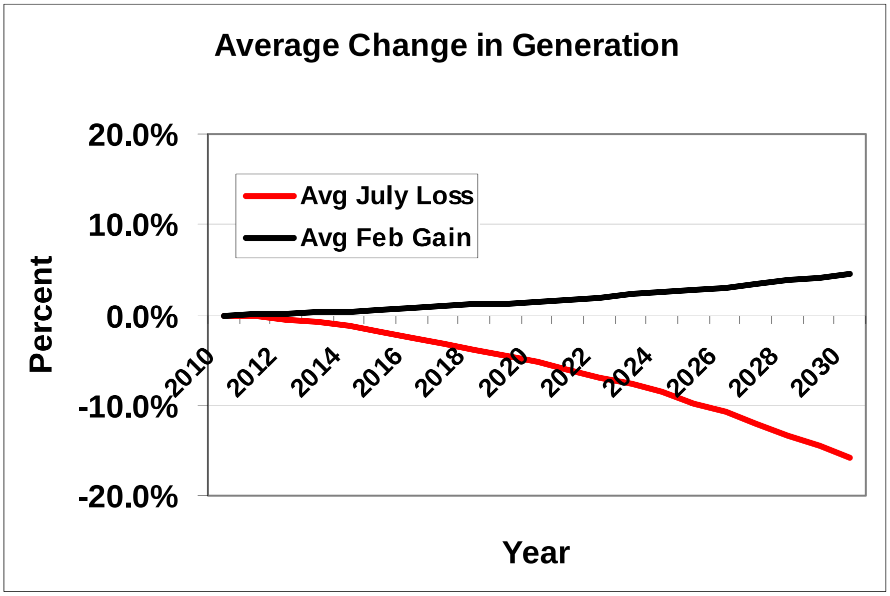


Figure L-12: Percent Annual Hydroelectric Generation Change



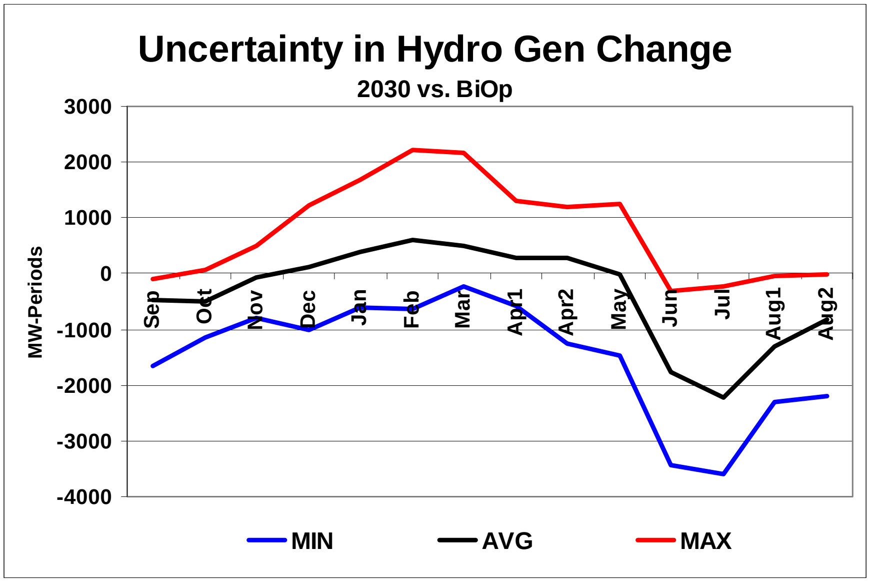
At the same time, winter demand is expected to decrease by about 600 average megawatts by 2030 while summer demand is expected to increase by about 1,000 average megawatts. Table L-2 summarizes these results, which when added together show a net load/resource balance increase of 1,200 average megawatts in winter and a net load/resource balance decrease of 3,220 average megawatts in summer. From an adequacy point of view, the winter season gets better while the summer becomes more stressed. In principle, these load/resource balance differences can be used to adjust the adequacy assessment calculations in Chapter 14. The net effect of doing so does not change the conclusion in that chapter, which is; that on an annual energy basis the region's power supply is adequate. A similar assessment of changes in winter and summer peaking reserve margins can be done and applied to the assessed values for peaking supply adequacy. This has not be done for a number of reasons but primarily because the climate change data used for this analysis is preliminary and is too uncertain to use for resource planning at this time. However, it can be concluded that all climate change scenarios will make the summer peaking situation worse.

Table L-2: Net Impacts to Energy Load/Resource Balance 2030 (MWa)

Changes to:	Winter	Summer
Generation	600	(2,220)
Demand	(600)	1,000
Net (G-D)	1,200	(3,220)

Assessing the true power system cost of climate change is difficult because in order to do so would require the development of two complete resource plans; one with climate change and one without. The Council's Portfolio Model does not currently have the capability to incorporate climate change impacts to hydroelectric generation and load as random variables. (This topic is discussed in more detail in the last section). However, an approximate power system cost can be made by assuming that changes in hydroelectric generation are priced at market values. Thus, months showing higher generation represent a net benefit to the region and months with lower generation represent a cost. In principle, generation changes for each month and for each water condition would be priced at the corresponding market electricity price (which varies by month and water condition). The uncertainty in the change in hydroelectric generation is illustrated in Figure L-13, which captures the minimum, maximum and average generation for each month.

Figure L-13: Uncertainty in Climate Induced Generation Change



In wet years, like the maximum curve in Figure L-13, the region stands to make money. And conversely in dry years, like the minimum curve, the region will likely have to purchase from the market to serve all of its loads. The average or expected cost of this scenario is on the order of $120 million dollars for 2030 climate conditions (but priced at today's prices). Figure L-14 shows the monthly distribution of costs, which has a similar pattern as the generation change chart (Figure L-9) and the flow change chart (Figure L-8). Applying the minimum and maximum ranges for changes to hydroelectric generation yields the graph in Figure L-15, which shows the range of potential power system costs for this scenario.

Even though a power system cost can be estimated using these techniques, no serious conclusion can be drawn as to whether climate change will be an economic benefit or cost to the region. There remains too much uncertainty in the data to make that assessment. We can conclude, however, that the net benefit or cost is directly related to the total volume of water that flows through the hydroelectric system on an annual basis. That parameter appears to be more important in assessing costs than the volume of water that is shifted from summer to winter.

Figure L-14: Estimated Power System Cost of Climate Change

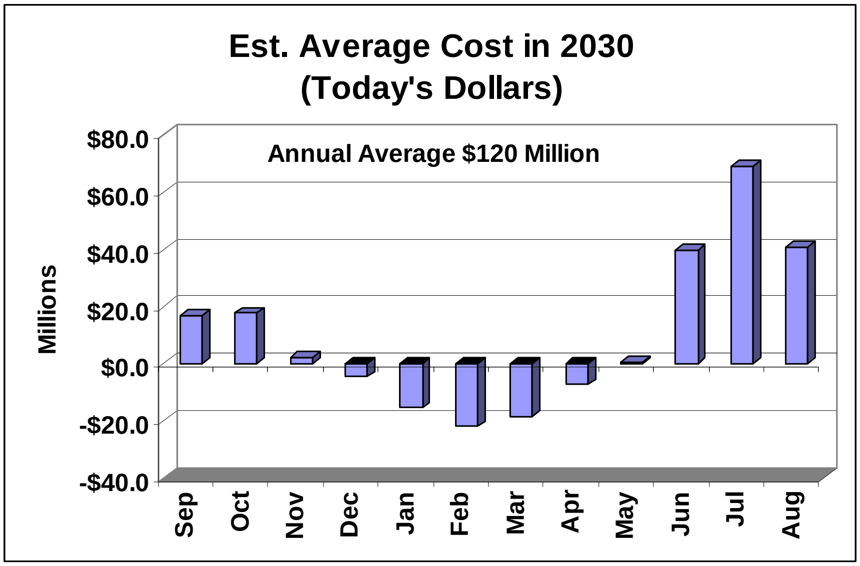
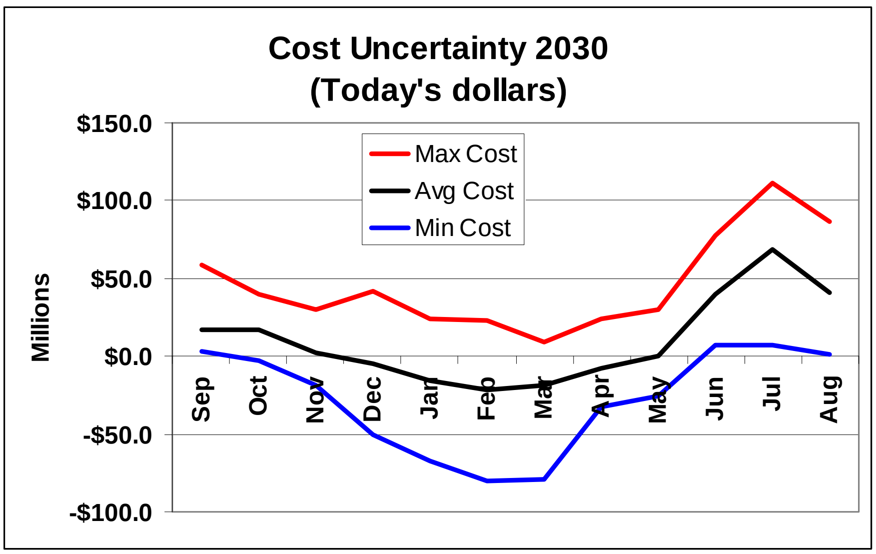


Figure L-15: Climate Change Cost Uncertainty



Other Impacts

Because river flows are likely to decrease in spring and summer, smolt (juvenile salmon) outmigration (journey to the ocean) and adult salmon returns will be affected. Lower river flows translate into lower river velocity and longer travel times to the ocean for migrating smolts. Lower river flows combined with a higher air temperature also means that water temperature may increase, another factor contributing to salmonid fish stress and mortality.

Besides the impacts to river flows, hydroelectric generation and temperatures, climate change will affect the Northwest's electricity interactions with other regions. Currently, both the Northwest and Southwest benefit from differences in climate. During the winter peak demand season in the Northwest, the Southwest generally has surplus capacity that can be imported to help with winter reliability. In the summer months, the opposite is true and some of the Northwest's hydroelectric capacity can be exported to help the Southwest meet its peak demand needs. This sharing of resources is cost effective for both regions.

Under a severe climate change scenario the Northwest could see increased summer demand with greatly decreased summer hydroelectric production. It is possible that the Northwest could find itself having to plan for summer peak needs as well as for winter peaks. In that case, the Northwest would no longer be able to share its surplus capacity with the Southwest. This would obviously have economic impacts in the Southwest where additional resources may be needed to maintain summer service. This would likely raise the value of late summer energy, thereby increasing the economic impact of climate change to the northwest.

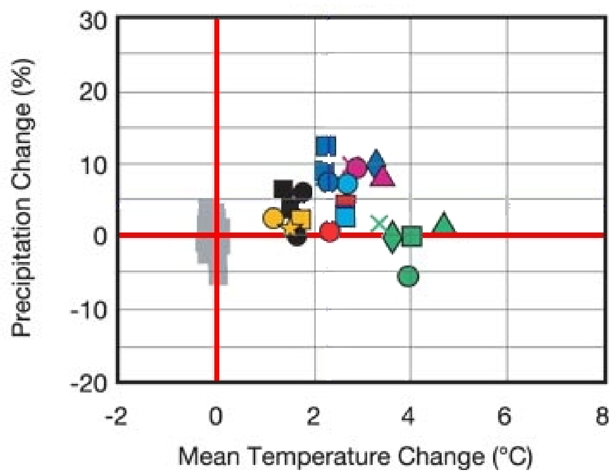
All of these impacts assume that no operational changes are made to the hydroelectric system. As described below in the section on mitigating actions, changes in the operation of the hydroelectric system may be significant. In which case, the impacts mentioned above may become better or worse. For example, if reservoirs were drafted deeper in summer months to make up for lost snowpack water, the increase in winter hydroelectric generation shown above would be reduced. A more realistic assessment of the physical and economic impacts must be done with an anticipated set of mitigating actions.

MODELING CLIMATE CHANGE AS A RANDOM VARIABLE

Ideally, climate change uncertainty and its impacts to hydroelectric generation and loads would be included as one of the random variables in the Council's Portfolio Model. Unfortunately, this cannot be done at this time for several reasons. First, the data required to do so is not available. Second, even if the data were available, the Portfolio Model is not equipped to accommodate it. Third, the relative likelihood of occurrence for each of the scenarios analyzed by the 20 Global Climate Models is not known.

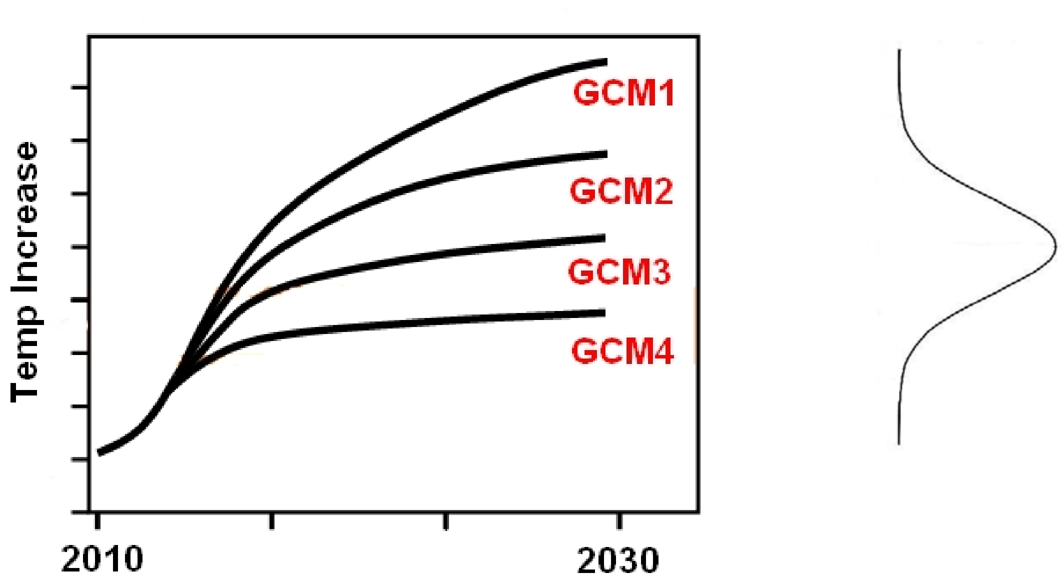
Figure L-16 below (similar to Figure L-1) illustrates the mean forecasted temperature and precipitation changes for a number of climate change scenarios. The data in Figure L-16 is not representative of analyses for the Northwest but rather is simply an illustration of the uncertainty surrounding these models. Each point in this graph represents the result of a single climate change scenario analysis for a particular future year. The gray area in this graph represents the normal uncertainty range for current climate conditions. Not surprisingly, the uncertainty in the climate change analyses (measured as the size of the spread of points) is much larger than the uncertainty surrounding current climate. As noted previously, all scenarios show a higher forecasted temperature but not all forecast higher precipitation.

Figure L-16: Illustration of Temperature and Precipitation Changes for Various Models



Recall (from Chapter 9) that the Regional Portfolio Model is a Monte Carlo computer program that assesses average power system cost and economic risk for many different resource plans. Each resource plan is, in essence, a potential supply curve of available new resources, including conservation, over the study horizon period. Each resource plan is examined over many different potential futures for the Northwest. Each future covers a 20-year period and draws from many random variables, including load, hydroelectric generation (water condition), electricity prices, fuel prices and carbon penalties to assess costs. In order to incorporate climate change uncertainty into the model as a random variable, the relative likelihood of occurrence for each climate scenario must be known. Then for each future examined, one particular climate change profile would be selected (i.e. one of the points in Figure L-16) as one of the many random variables used for that particular future. This concept is illustrated graphically in Figure L-17. In this figure, the mean forecasted temperature increase per year over a 20-year period is plotted for several different climate change scenarios (GCM1 through GCM4). In this example, a probability distribution is assigned to the set of scenarios, shown as the bell curve to the right of the graph. In this example, GCM2 and GCM3 are more likely to occur than GCM1 or GCM4 and thus they would be selected more often in the Monte Carlo simulation. Probability distributions for Northwest climate change scenarios, however, have not yet been developed.

Figure L-17: Illustrative Probability Distribution for Climate Model Results



Unfortunately, that is not the only problem that has to be overcome in order to incorporate climate change as a random variable into the Portfolio Model. Once a climate scenario is chosen by the model, its long-term effects on load and on hydroelectric generation will have to be interpolated back into the 2010 to 2030 study horizon period. Methods for performing that interpolation have not been extensively explored, although an example of one method has already been discussed earlier in this appendix.

But in spite of these difficulties, progress is being made. The Bonneville Power Administration, the Corps of Engineers and the Bureau of Reclamation have initiated a regional process to collect, review and make available all climate change data related to river operations. This process is being developed under the auspices of the RMJOC and will ultimately result in a web-based database that will include CIG data along with other related data needed to perform river operation analyses. Among other things, the additional data will include climate-change adjusted runoff forecasts and operating rule curves. The Council supports this work and will actively participate in its development.

RECOMMENDATIONS

The development of this power plan for the Northwest incorporates actions intended to address future uncertainties and their risks to electricity supply and to the economy. Such uncertainties include fluctuations in demand, fuel prices, changes in technology and increasing environmental constraints. Uncertainties related to climate change fall into two areas; 1) physical impacts that affect electricity demand and hydroelectric generation and 2) policies directed at reducing green house gas emissions that affect resource operation and cost.

Though the physical effects of climate change remain imperfectly understood, the Council has examined them and recommends that research continue in this area. In terms climate policy, the

Council has explicitly included assumptions regarding potential carbon penalties and renewable resource portfolio requirements into its Portfolio Model. A more detailed description of those policies and their impacts is provided in Chapter 11.

While no immediate actions regarding reservoir operations are indicated by this preliminary analysis of the physical impacts of climate change, the region should begin to examine and consider alternative reservoir operations that could potentially mitigate those impacts. Some of those actions may include:

- Adjusting reservoir rule curves to assure that reservoirs are full by the end of June
- Allowing reservoirs to draft below current end-of-summer limits
- Putting more effort into developing better runoff forecasting methods for the fall
- Negotiating with Canada to examine the potential for more summer releases from Canadian reservoirs
- Using increased winter streamflows to refill reservoirs
- Exploring the development of non-hydro resources to replace winter hydroelectric generation and to satisfy higher summer needs.