Northwest Power and Conservation Council

June 1, 2004

MEMORANDUM

TO: Council Members

FROM: Dick Watson

SUBJECT: Review of Draft Sections of the Power Plan and discussion of the results to date of the Portfolio Analysis

Attached are:

1) A summary of the status of the various sections of the Power Plan. The sections that have been through an initial editing by the Public Affairs Division are noted as is the status of their review with the Power Committee.

2) A number of draft chapters of the power plan. They are:
   a) The draft of Chapter 1 –*Introduction*. This is a discussion of the recent experience in the region and the issues identified for this power plan.
   b) The draft of Chapter 2 – *Current Status and Future Assumptions*. This chapter describes the historical and current status of demand and resources in the region and forecasts for demand, fuel prices, and electricity market prices.
   c) The draft of Chapter 3 – *Resource Alternatives and Characteristics*. This is a description of the different demand side and generating resources that are being considered in this plan. Estimates of availability and cost are provided. The sections on Conservation and Demand Response are included. The write-up of the section on generating resources has not yet been completed.
   d) The draft of Chapter 4 – *Risk Assessment and Management.* This chapter provides a description of how we are approaching risk in this plan. It provides definitions of terms and outlines the analytical approach being used. The Power Committee has not reviewed this section.
   e) The draft of Chapter 11 – *Transmission Issues and Requirements.* This draft describes the issues facing transmission in the region and the approaches being developed to address those issues. A section presenting the results of analysis of transmission requirements to access specific resources is not yet complete.
   f) The draft of Chapter 12 – *Fish and Power.* This chapter proposes identifies issues where better coordination of fish and power consideration at the planning stage (as opposed to

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in-season operations) would be helpful and proposes a mechanism to address this. The Power Committee has not reviewed this section.

g) The draft of Chapter 13 – *The Future Role of Bonneville in Power Supply*. This section identifies some of the issues that have let to consideration of changes in how Bonneville carries out its role in power supply and summarizes the Council's recent recommendations. The Power Committee has not reviewed this section.

3) The proposed process for review and adoption of the Power Plan.

4) Finally, there is a discussion of the portfolio analysis and some of the tentative conclusions we have drawn.

Power Plan Status -- May 28, 2004						
Section		**Status**	**Initial Power Com. Review**	**Public Affairs Review**	**Second Power Com. Review**	**Council Review**
	Executive Summary & Action Plan	Preliminary draft – awaiting completion of Portfolio Analysis				
1	Introduction	Draft Complete	✓	✓		
2	Current Status and Future Assumptions	Draft Complete	✓ (partial – elec price forecast)	✓		
3	Resource Alternatives and Characteristics	Partially complete – awaiting completion of description of generating resource alternatives	✓ (Cnsr-vtn & DR)	✓		
4	Treatment of Risk in the Power Plan	Draft Complete		✓		
5	Portfolio Analysis and Recommended Plan	In Process				
Analysis, conclusions and Recommendations:						
6	Resource Adequacy	In Process				
7	Conservation	In Process				
8	Demand Response	In Process (Partially completed – awaiting completion of portfolio analysis)	✓ (partial)	✓ (Partial)		
9	The role of renewables & climate change miti-gation	In Process				
10	Other Generating resources issues	In Process				
11	Transmission issues and requirements	Partially completed, awaiting completion of transmission analysis	✓ (partial)	✓ (partial)		
12	Fish and Power	Draft Complete		✓		

Section		Status	Initial Power Com Review	Public Affairs Review	Second Power Com. Review	Council Review
13	Future Role of Bonneville in Power Supply	Draft complete		✓		
14	Action Plan	In process				
Appendices (detailed technical backup information)						
Demand Forecast		Draft Complete		✓		
Fuel Price Forecast		Draft Complete		✓		
Market Price Forecast		Draft Complete				
Conservation Resource Assessment		In Process				
Demand Response Assessment		In Process				
Generation Resource Assessment		In Process				
Description of the Portfolio Model		In Process				
Climate change issues		In Process				
Fish and Power		In Process				

Introduction to the Fifth Power Plan

The Council's first power plan, adopted in 1983, was developed in the aftermath of the region's effort to construct five nuclear power plants. Although only one of these power plants was completed, the cost of that plant and the uncompleted plants were the primary reasons for a 66-percent real increase in retail rates in the region in the early 1980s. This caused demand to plummet and caused economic hardship for many in the region. In response to this experience, the Council's first plan brought innovations to electricity system planning. These included recognition of the price elasticity of demand in forecasting and methods for assessing and managing the risks associated with capital-intensive, long lead-time generation. It also furthered electricity policy innovations such as treating conservation -- the more efficient use of electricity -- as a resource comparable to generation.

The Fifth Power Plan has many parallels. It comes on the heels of the 2000-2001 Western electricity crisis. This crisis manifested itself in extremely high wholesale power prices (Figure 1-1) and the threat of blackouts that persisted for almost a year.

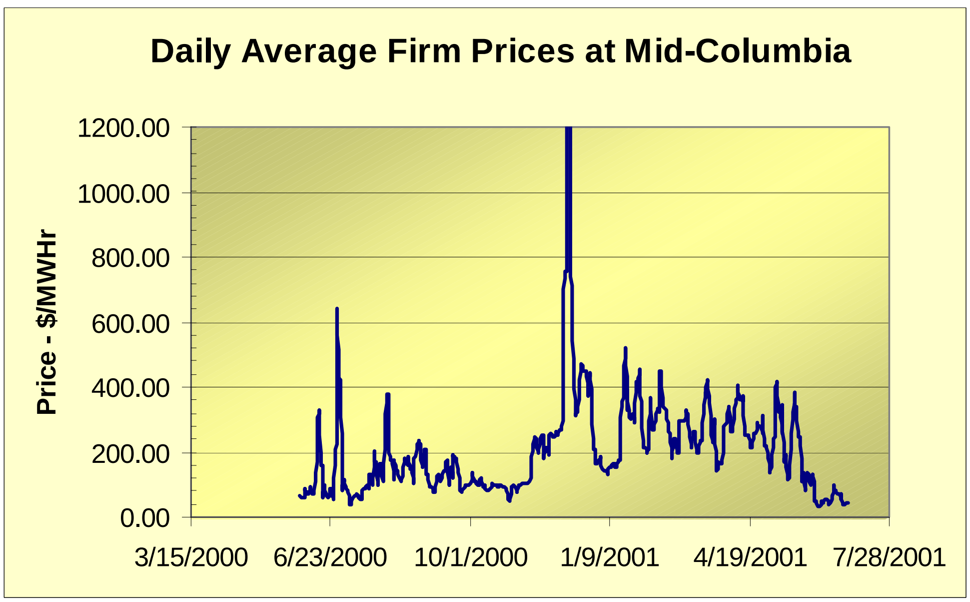

Figure 1-1

(EX\price data\,mid-c spot prices)

The high wholesale prices eventually caused retail prices to increase by 25 to 50 percent. Many utilities entered into long-term contracts for power supply at high prices at the height of the crisis. As a consequence, although wholesale prices have returned to normal levels, retail rates have not yet returned to pre-crisis levels (Figure 1-2).

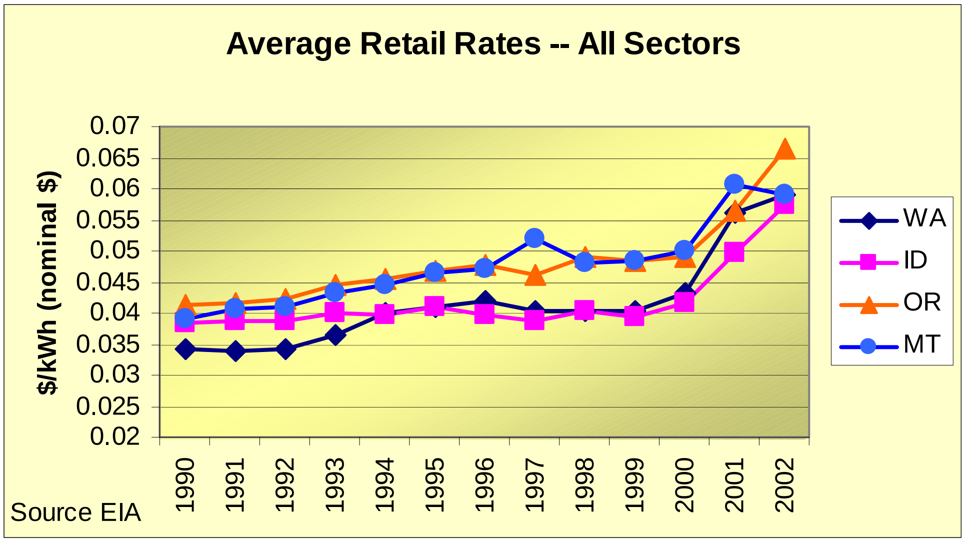

Figure 1-2

(EX\fifthplan\elec.prices19902002)

Similarly, demand remains well below pre-crisis levels (Figure 1-3). Most of this is due to the fact that much of the electricity-intensive aluminum industry remains shut down. However, other industries and economic activities have also been affected.

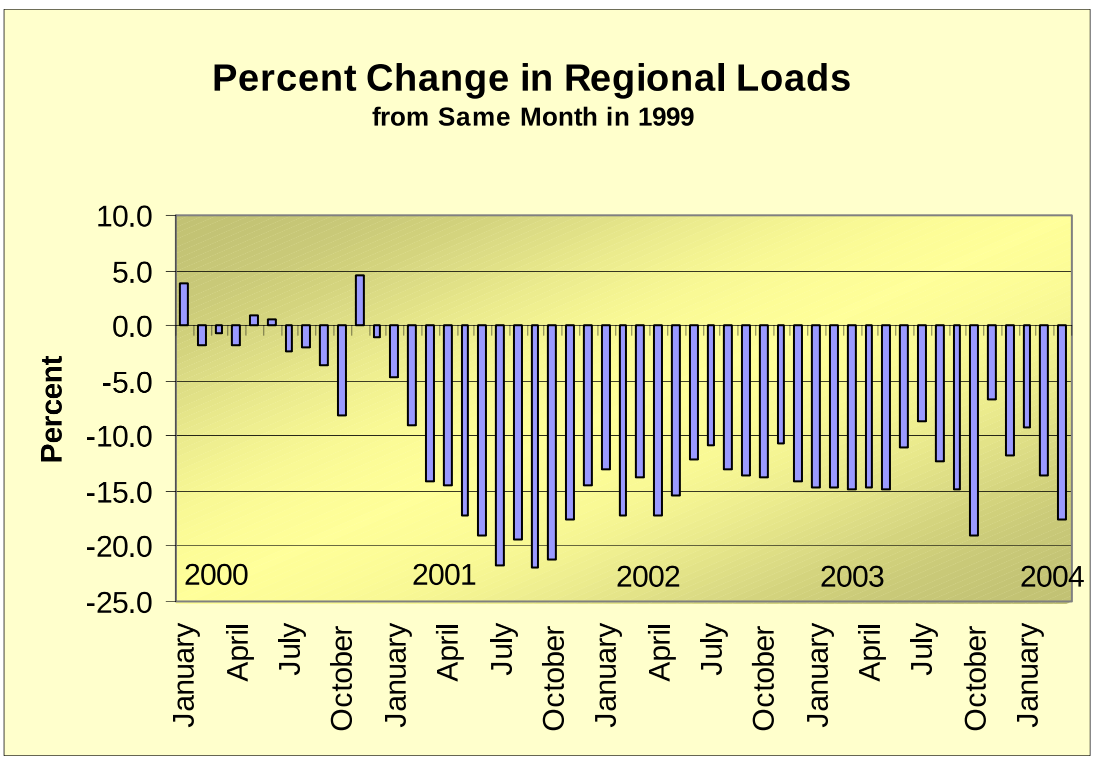

Figure 1-3 (update)

(TM\EX\loadtracker6)

The challenges we face as a region are similar to those we faced when the first power plan was published: to build on the lessons of the recent past and to provide leadership in planning and policy that will help assure the region an adequate, efficient, economic and reliable power supply in the years ahead. The Fifth Power Plan is also concerned with adapting to the rapidly changing circumstances of the power industry. Change is likely to be more dynamic than in the past. If the Council's plans are to provide useful guidance, they must adapt more rapidly to these changing conditions.

What caused the Western electricity crisis?

The Western electricity crisis has been referred to as the "perfect storm" – the result of the confluence of a number of adverse trends and events. It had its roots in several years of under-investment in generating and conservation resources. It was triggered by the onset of poor hydro conditions in the later spring of 2000 leading to the second-worst water year in the Northwest's hydrological record in 2001. It was made much worse by a deeply flawed electricity market design in California and opportunism by some of the participants in that market. And many believe it was prolonged by the reluctance of the Federal Energy Regulatory Commission to impose West-wide price caps.

The poor hydro conditions in 2001 resulted in almost 4,000 average megawatts less hydroelectric energy available than in an average year, and even less compared to the relatively wet years of 1995-1999. The reduced hydro generation affected not only the Northwest, but California and the Desert Southwest as well. Net exports from the Northwest Power Pool Area[1] for May through September averaged 2,700 average megawatts less in 2000 and 2001 than in the preceding three years.

However, the poor hydro conditions and the flawed California market are unlikely to have triggered the Western electricity crisis had it not been for the extremely tight resource situation in the Northwest and West leading into 2000. Here in the Northwest, the in-region critical water load-resource balance was increasingly negative (loads greater than regional resources) throughout the 1990s (Figure 1-4). By the year 2000, the deficit had reached 4,000 average megawatts.

[1] The Northwest Power Pool Area encompasses Alberta, British Columbia, Washington, Oregon, Idaho, Montana, Wyoming, Utah and Northern Nevada.

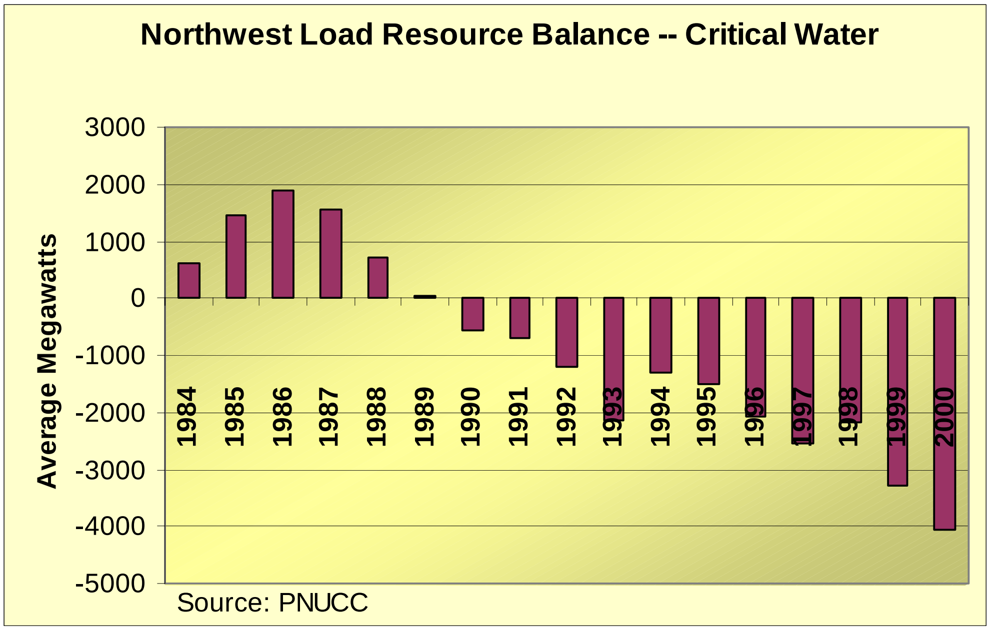

Figure 1-4

(ex\fifthplan\PNUCCbalance)

During most of the late 1990s, the development of generation in the Northwest and, for that matter, the rest of the West, was effectively at a standstill. Similarly, utility investment in conservation during that period was less than half the cost-effective levels identified by the Council.

Concerned by the growing deficits, the Council undertook a study of regional power supply adequacy. That study, released in early 2000, estimated that the probability of being unable to fully serve Northwest load would climb to 24 percent by 2003, even when accounting for the ability to import power in the winter and to draft reservoirs beyond normal limits in emergencies. The analysis also indicated that 3,000 megawatts of new resources would be necessary to bring the loss of load probability down to the acceptable industry criterion of 5 percent.[2] What the report failed to emphasize was that the probable leading indicator of such resource scarcity would be price volatility. The prices of 2000-2001 brought that lesson home very clearly.

Contributing Factors

Neither the Council's study nor any of the other indicators of growing resource inadequacy stimulated a rush to develop new resources. Some new resources were under development prior to the crisis. However, they were not enough soon enough to avert the crisis. Why did the Northwest and the rest of the West allow loads and resources to get so far out of balance?

[2] Northwest Power Supply: Adequacy/Reliability Study Phase I Report , March 2000.

Naive Faith in "The Market"

One explanation is the infatuation with the competitive wholesale power market that was prevalent in the late 1990s. Why should a load-serving entity build new resources or enter into long-term contracts when the invisible hand of the competitive market will take care of long-term supply? A long period of low spot market prices seemed to validate this view. However, it should have been clear that the market was not taking care of supply. Deficits continued to grow, but very few new power plants were being built. Wholesale prices in the years immediately preceding the summer of 2000 were generally below what it would take for a new generator to fully recover its costs, in part because of greater-than-average hydro production during that period. Few independent power producers were willing to undertake the risk of building a plant without having a significant portion of a plant's capability committed to long-term contracts. This was particularly so in the Northwest where good hydro conditions can depress market prices for extended periods. Many observers have argued that spot-market energy prices alone were unlikely to support development of needed capacity unless you were willing to accept periods of very high prices. To address this problem, the PJM Interconnection[3] and some other areas instituted some form of capacity payment with varying degrees of success. However, no such mechanisms were introduced in the West.

Fear of Retail Competition and Stranded Costs

Another factor keeping utilities from making commitments to new resources was fear of retail competition. During the mid-to-late 1990s, there was a great deal of discussion of retail competition. Some states, such as Montana and, on a more limited basis, Oregon, opened their retail markets to competition. Others were considering it and there was speculation that Congress might impose retail competition. In the face of these developments, utilities were concerned that if they were forced to open their service territories to competition, they might lose customers to competitors and their investments in new resources would be "stranded," i.e., the utility would not be able to recover costs of new resources or long-term contracts. Consideration of the growing deficits should have suggested that a reasonable level of investment in new resources would not become stranded. Nonetheless, concerns about retail competition and stranded costs undoubtedly played some part in retarding resource development.

Uncertainty Regarding the Role of Bonneville

Another contributing factor was uncertainty with regard to the role Bonneville would play in serving future Northwest loads. Most utility and DSI contracts with Bonneville were to expire in October of 2001. Decisions about the signing of new contracts for subsequent service did not begin until 2000. This meant that both Bonneville and its customers were uncertain about who would have the responsibility for acquiring new resources until the Western electricity crisis was practically upon us. In the end, Bonneville found itself in the position of having to acquire 3,300 megawatts in a relatively short time during a period of extremely high prices. Had there not been the

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[3] The Pennsylvania, Jersey and Maryland Interconnection. It is now the regional transmission organization covering much of the mid-Atlantic states.

uncertainty, Bonneville or the utilities may have taken steps to acquire resources earlier that would have lessened the impacts of 2000-2001.

Failure of Planning

Finally, it seems clear that planning in the 1990s, including that of the Council, failed to fully appreciate and factor into its decisions the risks facing the industry. In particular, these included the risks associated with reliance on a potentially volatile wholesale market and risks associated with gas-fired generation that depends on the also volatile natural gas market. If planning had done a better job of reflecting the risks and their potential impacts, might load-serving entities have taken action to mitigate those risks? In February of 2000 the Council released a report that put a spotlight on the region's worsening resource condition. However, it was too late to elicit much of a response from the region.

The Response to the Crisis

Ultimately, Northwest utilities, independent developers, businesses, governments and citizens responded to the electricity crisis with ingenuity and effectiveness. There were three primary responses: new generation, both small-scale and larger conventional generation; load reduction through both efficiency improvements and, primarily, demand reduction; and changes in the operations of the hydroelectric system.

Generation

By December of 2001, almost 1,300 megawatts of new permanent generation had entered service, approximately 1,100 megawatts of which were gas-fired combustion turbines. Another almost 3,800 megawatts was under construction, almost 2,900 megawatts were permitted, and over 10,000 megawatts were in the permitting process. The great majority were gas-fired plants, and most of those were combined-cycle units. However, there were several hundred megawatts of wind power developed as well. The developers were primarily Independent Power Producers (IPPs). This pattern was seen throughout the West.

One of the surprises was the amount and speed with which smaller-scale generation appeared in the region. This generation primarily came in the form of trailer or skid-mounted reciprocating engine generator sets and small gas turbine generators. Between the beginning of the crisis and December 2001, over 700 megawatts of temporary generation came into service in the region. More was planned. Utilities and industries that were exposed to market prices and speculative developers undertook these projects. The power from these generators was relatively expensive but certainly less expensive than the market prices of that time. Typically this generation was also more polluting than larger scale generation. With the fall in market prices in the summer of 2001, much of the temporary generation was retired. Of the 700 megawatts put in service, over 180 megawatts was "retired" by December of 2001 and almost all was retired by December 2002.

At the present time, approximately 4,000 megawatts of new capacity has come on line in the Northwest since January of 2000, over 500 megawatts of which is wind, and over

1,400 megawatts is partially complete, although construction has been suspended. The great majority of this is gas-fired. While the amount of new generation is impressive, most of it effectively "missed the party." By the time the generation became operational, prices had fallen and along with them, the profits anticipated by the developers. At present there are hundreds of megawatts of under-utilized new generating capacity in the region, most developed and owned by independent power producers. The good news is that the capital risk associated with this capacity is borne by the investors rather than the consumers of the region. The bad news is that the credit ratings of independent power producers have declined precipitously. The industry is not dead, but it has been severely wounded.

Load Reduction

Demand for electricity in the region was eventually reduced by as much as 20 percent or about 4,000 average megawatts by the summer of 2001. This load reduction was accomplished through two means: efficiency and, primarily, demand response.[4]

In 1999, Northwest utilities implemented 37 average megawatts of efficiency improvements in their customers' homes, offices, stores, factories, farms and so on. This was a little more than one third of what the Council estimated to be cost-effective in the Fourth Power Plan. Although high wholesale prices began hitting in May and June of 2000, annual savings for 2000 were only increased by about a third as it took some time to ramp up efforts. However, for 2001, efficiency savings increased to 150 average megawatts. Much of the savings came as a result of rebates on efficient compact fluorescent lights. Over 9 million were sold in the Northwest in 2001. Fortunately, the groundwork for this program had largely been laid in the preceding years so that the program could be rolled out relatively quickly. It's not clear that we could do that again.

While the efficiency response was impressive, demand response made up the great majority of the load reduction. Demand response means a reduction in electricity use unrelated to the efficiency of the facility, equipment or process. It can be accomplished through a reduction or cessation in the electricity-using activity (e.g., making sure unnecessary lights are turned off, only running one shift in a factory or shutting down entirely) or by switching to a different source of electricity (installing self-generation) or a different energy source altogether (e.g., switching to direct use of natural gas). All three methods were employed in 2000-2001.

Demand response was accomplished through a number of different inducements. These included appeals to the public-spiritedness of consumers by governors and other public figures, price signals, and utility "buyback" offers – offers by utilities to pay for reduced consumption. The governors of the Northwest states raised the visibility of the severity of the electricity situation and made public appeals for cutbacks. Some industrial customers exposed to market prices responded in a variety of ways to the sharp increases in wholesale prices, including fuel switching, self-generation, cutbacks and shutdowns,

[4] "Demand response," as will be discussed later, is a change in the service (level, quality or timing) that is chosen voluntarily by the consumer, which reduces electricity use or shifts it to a different time. If the change in service were imposed on the consumer involuntarily it would be "curtailment".

albeit at some significant economic expense. Sixty-three percent of the load reductions came about through various forms of buybacks, over 90 percent of which came from the aluminum industry. In the residential sector, programs like "20-20" and its variants offered ratepayers a percentage reduction in their bill for reducing their consumption by the same percentage relative to the same period in the previous year. None of these load reductions came cheap, but they were cheaper than the alternative of paying the market price for the electricity.

As impressive as the load reductions were, they came too late to avoid several months of extreme wholesale prices. As shown in Figure 1-5, load reduction did not really begin taking effect in a significant way until more than seven months after the onset of wholesale prices that were several hundred percent higher than normal. Had there been

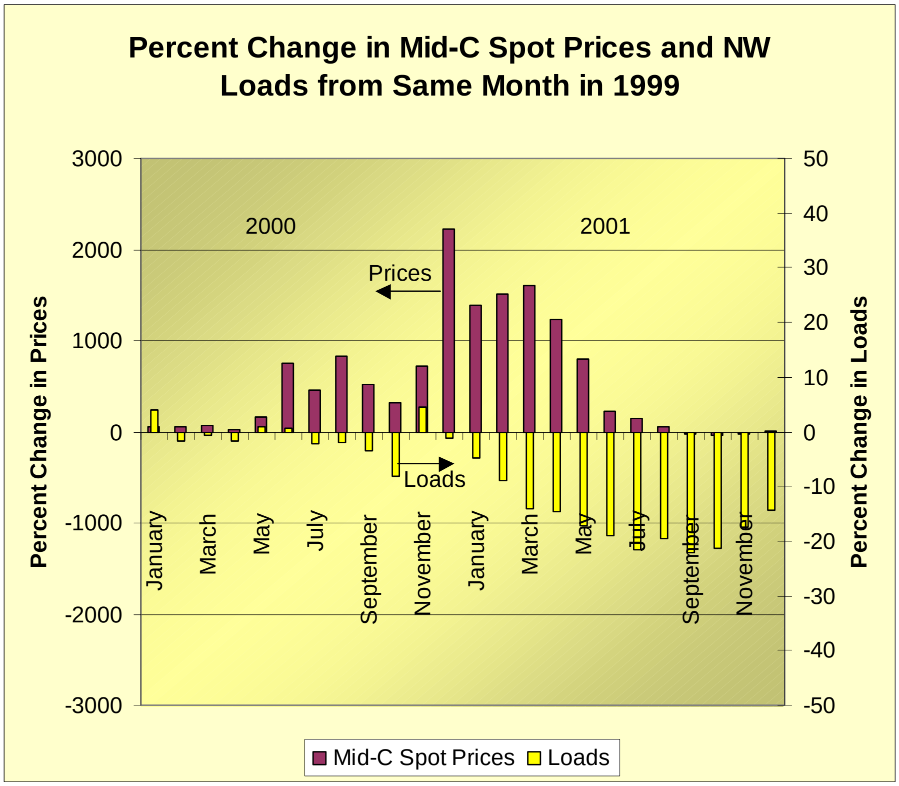

Figure 1-5

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a more rapid response of loads to wholesale prices, it might have partially mitigated the high wholesale prices that the region was experiencing. Similarly, had investment in conservation continued at cost-effective levels throughout the 1990s there would have been at least a couple hundred megawatts less load exposed to the high prices.

Hydro Operations

The third leg of the stool in response to the electricity crisis was changes to the operation of the hydroelectric system that increased generation. The most significant change was reduction in bypass spill at the John Day, The Dalles, and Bonneville projects. Bypass spill (running water over a dam's spillways instead of through the turbines) is intended to reduce injury and mortality of out-migrating juvenile salmon and steelhead. However, from a power supply standpoint, spill is energy lost. Most of the spill reduction took place in 2001. In total, reducing spill called for in NOAA Fisheries' 2000 Biological Opinion (BiOp) added an additional 4,500 megawatt-months to the region's energy supply, much of that coming in late spring and early summer when power prices were still at extremely high levels. It also allowed storing additional water in Canadian reservoirs in case poor water conditions continued into the winter of 2001-2002.

The use of spill reduction also highlighted the conflict between fish and power. Some viewed it as an example of the power system being willing to violate fish operations instead of making the needed investments in an adequate power supply. Others viewed it as a reasonable and prudent step given the high cost and poorly demonstrated biological effectiveness of spill. The debate continues today.

The Challenges Going Forward

It is tempting to believe that the factors that led to and prolonged the Western electricity crisis are no longer of concern. Have we learned our lesson? Certainly the possibility of additional jurisdictions moving to retail competition is much diminished if not eliminated. There is also a renewed enthusiasm on the part of many utilities and their regulators for the vertically integrated utility where the utility owns generation and is less reliant on "the market." Similarly, many utilities now have experience with demand management programs that could, if maintained, serve them in good stead should another crisis begin to emerge.

In many respects these are positive developments that represent a retreat from excesses of the late 1990s. However, we believe it would be a mistake to think it could not happen again. It seems likely that we will have sufficient resources for several years. Combine this with a few years of good water and the resulting low market prices could make the lessons of the past few years fade unless those lessons have been built into the structure of our electricity system.

It is likely we will continue to see a mix of vertically integrated utilities, a federal power-marketing agency, local distribution utilities and competitive wholesale suppliers in the regional power system for the foreseeable future. This mix will have elements of federal, state and local regulation and competition. This mix results in uncertainty regarding roles and responsibilities and lacks some of the elements necessary for it to function effectively. The challenge for this power plan is to provide insights into what will make such a system function effectively and equitably not only now, when the experience of 2000-2001 is fresh in our minds, but in the longer term.

Vision for the Northwest Power System

Our vision is a well-functioning (adequate, economical, efficient, reliable) electrical system comprised of a mix of independent and utility-owned generation, regulated transmission and distribution, and an effective consumer demand response mechanism. It is a system in which efficiency and renewable resources compete on an equal footing with conventional generation and that includes environmental considerations when making resource decisions. It is a system that recognizes the risk inherent in the power industry, and plans and implements actions in ways that effectively manages that risk. The characteristics of that system are:

- The region puts in place resource adequacy monitoring and planning functions.
- Resource planning includes robust assessment of risk and the options for risk mitigation.
- There are clearly defined responsibilities and accountability for resource adequacy, reliable power system operation, and transmission system expansion.
- The wholesale power market is transparent, with open transmission access and fair rules for all participants, including the demand side of the market.
- There are reasonably consistent wholesale power market and transmission access rules across the integrated electrical grid.
- There is active market oversight and monitoring to ensure efficient operation and to prevent market power abuse ensuring the accountability of market participants to the consumers ultimately served by those markets.
- The system preserves state authority and accountability over retail electricity markets to ensure fair and reasonable consumer prices for monopoly customers.
- The region continues to pursue and acquire cost-effective conservation and high efficiency resources through regional, Bonneville, utility and state programs that supplement competitive market incentives where necessary.
- Electricity pricing and regulation provide adequate incentives for efficient utilization and expansion of the region's generating resources and transmission system.
- Electricity pricing and regulation provide incentives for efficient uses of electricity by consumers; promote cost effective demand-side measures, including customer-owned generation as alternatives to transmission system expansion; and do not create barriers to cost effective distributed generation or renewable resources.
- The region fulfills its fish and wildlife protection and mitigation responsibilities as they relate to the hydroelectric system in ways that are effective, efficient and equitable.
- A sustainable role is defined for Bonneville in which it markets the existing Federal Columbia River Power System resources on an allocation basis, provides equitable benefits to the residential and farm customers of the region's investor-owned utilities, and meets additional load growth only through (1) conservation, (2) bilateral incrementally priced contracts with individual customers or groups of customers, (3) power freed up by ending any DSI allocations done on an interim basis, or any turn-back of public utility allocations.

Focus for the Fifth Power Plan

The Fifth Power Plan can help the region achieve the vision described above. The challenge for the Fifth Power Plan is two-fold. The first relates the Council's traditional power planning role. It is to develop more robust planning methods for assessing and managing the risks inherent in the industry structure and to use these methods to develop resource strategies that will meet the region's electricity needs at lowest cost with acceptable risk.

The second and related challenge is to provide insights into the resolution of some of the key issues affecting the industry in the Northwest that are impediments to achieving the vision. These issues include at least the following:

- Determining what constitutes resource adequacy and identifying the incentives (regulatory or financial) for assuring resource adequacy;
- Contributing to improving the way we plan and pay for transmission system expansion and how we ensure transmission is operated reliably, efficiently and equitably;
- Identifying the necessary and sufficient steps to enable effective demand side participation in the market;
- Identifying the means of sustaining investment in cost-effect conservation and renewable resources;
- Determining the value of resource diversity for the region and the means of achieving it;
- Determining how to meet the requirements for power and fish recovery effectively, efficiently and equitably; and
- Helping define the future role of the Bonneville Power Administration in power supply. Experience of the last few years suggests that Bonneville is, by nature of the requirements and constraints under which it operates, ill suited to managing the financial and political risks of a large role in resource development. An alternative is required that limits Bonneville's risk exposure in resource development while still ensuring that cost-effective conservation and renewable energy and fish recovery goals continue to be met.

Current Status and Future Assumptions

Introduction

This section describes the current status of the region's electricity system, some relevant historical trends leading to that status, and the Council's projections of how that status might change in the future. An understanding of our current situation and how we got here is important for the Council's power plan. As described in the introduction, there have been dramatic changes in the region's energy situation over the last few years. These changes are not limited to this region, however. We are increasingly linked to national and international energy markets and policies. Understanding these changes and the risks and opportunities they present is important for the Council's power plan.

In this discussion, the Council takes a relatively long-term perspective, as is necessary for a 20-year power plan. At the same time, an ongoing assessment and monitoring of the regional electricity situation requires some attention to current conditions and their implications. In the discussion that follows, the Council attempts to place our current situation in the context of historical trends and potential future changes and directions that underlie the analysis in this power plan. Any consideration of the future is necessarily uncertain. The forecasts discussed in this plan represent the Council's estimates of a range of possible futures. The power plan directly addresses the uncertainty of the future and appropriate strategies for minimizing the risks associated with unforeseen changes.

The key elements of the current and future electricity situation are the demand for electricity, the amount and cost of electricity generation capability in the region, transmission and exchange opportunities between the region and the rest of the West, potential and cost of conservation and demand management, and regional and national energy and environmental policies. Demand defines the need for electricity while generation, demand management and conservation are the means of meeting those needs. Transmission is the delivery mechanism and the chief means of operating the system. Policies shape the context and, to a large extent, the incentives that affect the adequacy and economy of the transmission system and the electricity supply. The types of electricity supply and efficiency investments that exist in the region, and additions that might be made in the future help define the nature of the risks inherent in the electricity system and its costs.

Demand for Electricity

It has been 20 years since the Council's first power plan in 1983. In the 20 years prior to the Northwest Power Act, regional electrical loads were growing at 5 percent per year (Figure 1). Between 1960 and 1980 loads increased from 6,300 average megawatts to 16,600 average megawatts, an increase of over 10,000 average megawatts. In the 20 years since the Power Act (1980-2000), loads grew by 4,600 average megawatts, an average annual growth rate of only 1.2 percent.

The dramatic decrease in electricity demand growth after the Power Act was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and 2000 than it did between 1960 and 1980. The cause of the change was decreased electric intensity of the regional economy. As shown in Table 1, electric intensity, both in terms of use per capita and use per employee, increased between 1960 and 1980, but decreased significantly after 1980. This shift reflected a changing industrial structure, higher electricity prices, and regional and national conservation efforts.

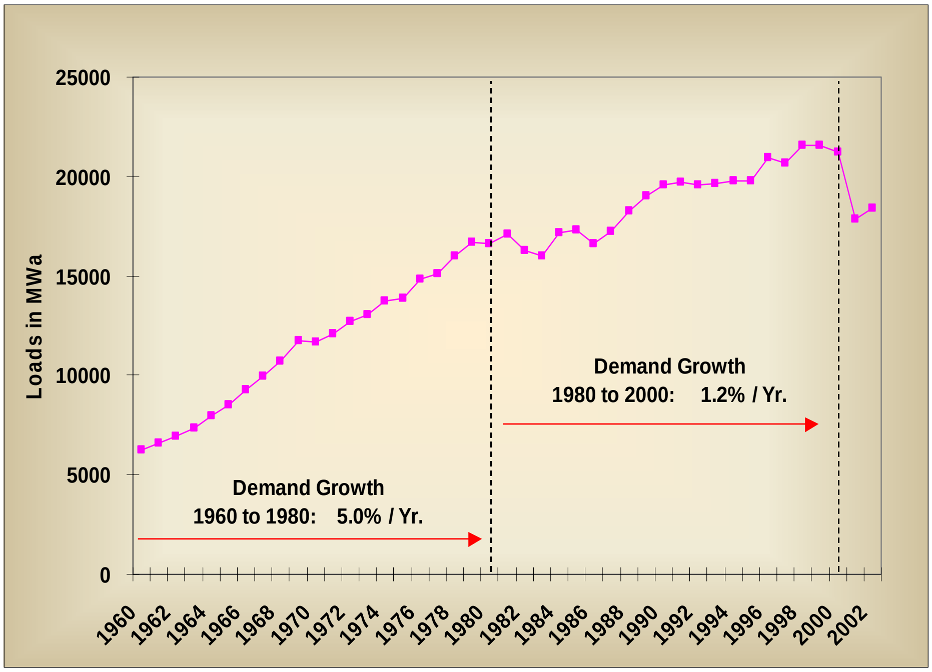

Figure 1: Forty-Three Years of Pacific Northwest Electricity Demand

Table 1: Changing Electric Intensity of the Regional Economy

Year	Electricity Use Per Capita (MWa / Thousand Persons)	Electricity Use Per Employee (MWa / Thousand Employees)
1960	1.13	3.81
1980	2.07	5.10
2000	1.93	4.03

The Council's first power plan was able to anticipate many of the effects of changing industrial structure and electricity prices on the demand for electricity. In addition, the first plan identified conservation opportunities and encouraged the region to achieve them. Actual 2000 electricity demand and conservation achievements correspond closely with what was anticipated in the 1983 power plan in amount if not in composition. The plan predicted 2000 electricity loads of 23,400 average megawatts (average of medium-low and medium-high forecasts), which would be reduced by 2,500 average megawatts of conservation to 20,900 average megawatts. The Council estimates that the region had actually achieved 2,500 megawatts of conservation by 2000, and regional electricity loads in that year are estimated to have been 21,200.

The third decade following the Northwest Power Act has started out similar to the first decade. Around 1980, the region experienced dramatic increases in the price of electricity, followed by an economic recession that hit the region particularly hard. In late 2000, the region again experienced large increases in the price of energy, accompanied by a moderate recession. Figure 2 illustrates this price history. These price increases have decreased electricity demand and increased the implementation of conservation programs, but the largest effects were on energy intensive industries, especially the region's 10 aluminum plants. The electricity price increases of the early 1980s turned many of the region's aluminum plants into swing plants that tended to shut down during periods of low aluminum prices. The 2001 price increase resulted in the closure of all of the aluminum plants and the demand forecast assumes that many of the plants will remain closed. When all were operating, the aluminum plants could account for 15 percent of regional electricity demand. Their closure accounts for much of the drop in electricity demand after 2000 shown in Figure 1.

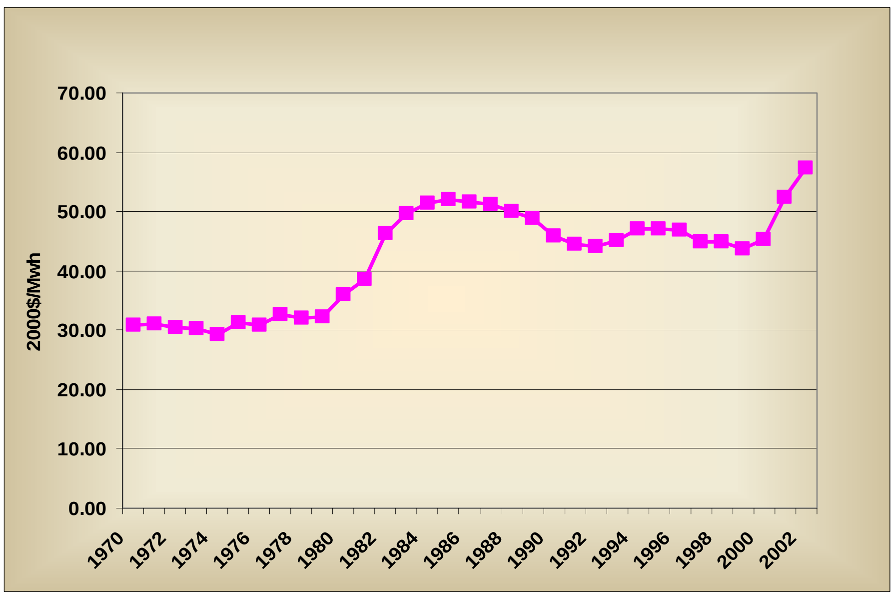

Figure 2: Historical Retail Electricity Prices in the Pacific Northwest

Electricity demand dropped by 2,800 average megawatts between 2000 and 2002. These recent demand changes were described in the introduction. Evidence available so far for 2003 does not indicate a significant increase in demand. This decrease in electricity demand has erased more than a decade of demand growth, leaving electricity loads at a level similar to 1989.

As a result of this demand reduction, and the expectation that aluminum loads will remain low, the medium demand forecast for this draft plan is significantly lower than in the Fourth Power Plan. The forecast of total electricity consumption in 2015 (the last year in the Fourth Power Plan) is 3,000 megawatts lower in the Fifth Power Plan forecast. The demand forecast is described in detail in Appendix **??**. Table 2 summarizes the Fifth Power Plan forecast. In the medium case, consumption is forecast to grow from 20,080 average megawatts in 2000 to 25,423 by 2025. However, current consumption levels are well below 2000 levels, and it will be several years before those levels of consumption are reached again. The range of forecasts reflects significant uncertainty about demand trends. The entire range, as well as periods of faster or slower growth within the trends, is incorporated into the portfolio risk analysis.

Table 2: Demand Forecast Range

	(Actual)			Growth Rates	
	2000	2015	2025	2000-2015	2000-2025
Low	20,080	17,489	17,822	-0.92	-0.48
Medium Low	20,080	19,942	21,934	-0.05	0.35
Medium	20,080	22,105	25,423	0.64	0.95
Medium High	20,080	24,200	29,138	1.25	1.50
High	20,080	27,687	35,897	2.16	2.35

Figure 3 shows the range of forecasts compared to historical consumption and compared to the range of forecasts in the Council's Fourth Power Plan. It shows that the medium demand forecast for 2015 is about equal to the medium-low forecast in the Council's Fourth Power Plan.

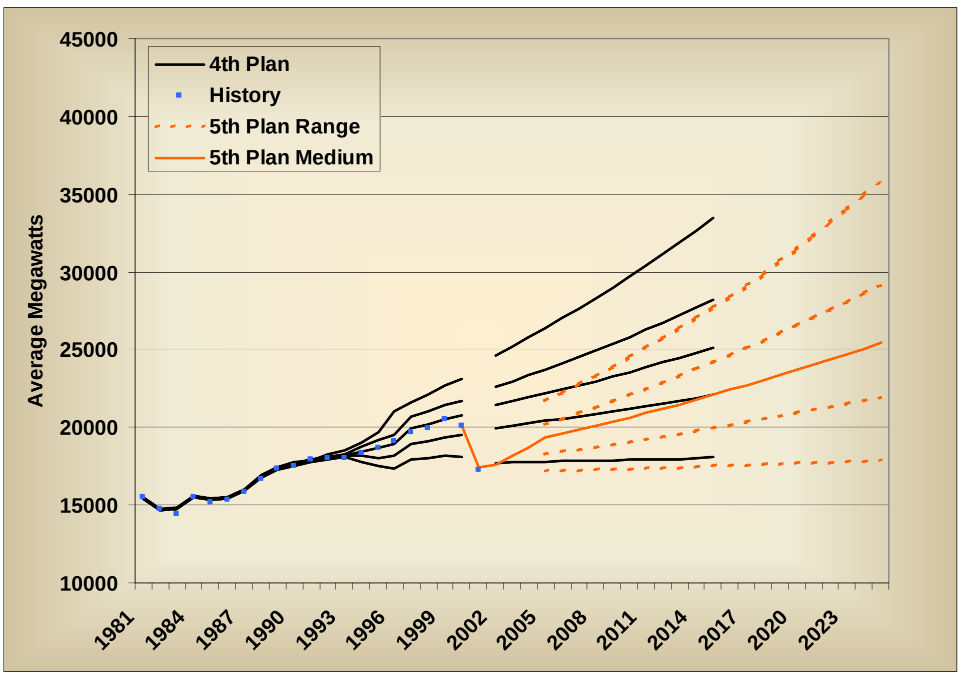

Figure 3: Demand Forecast Range Compared to History and Council's Fourth Power Plan

Regional Electricity Supply

The region's electricity supply is still dominated by hydroelectric power. The annual energy generating capability in the region, under critical water conditions, is estimated to be about 23,000 average megawatts. Critical water is the historical volume and temporal pattern of river flows that result in the least firm energy production from the system. Figure 4 shows that about half of the regional energy generation comes from hydropower. Coal and natural gas make up most of the remainder, with smaller contributions from nuclear, wind and other sources.

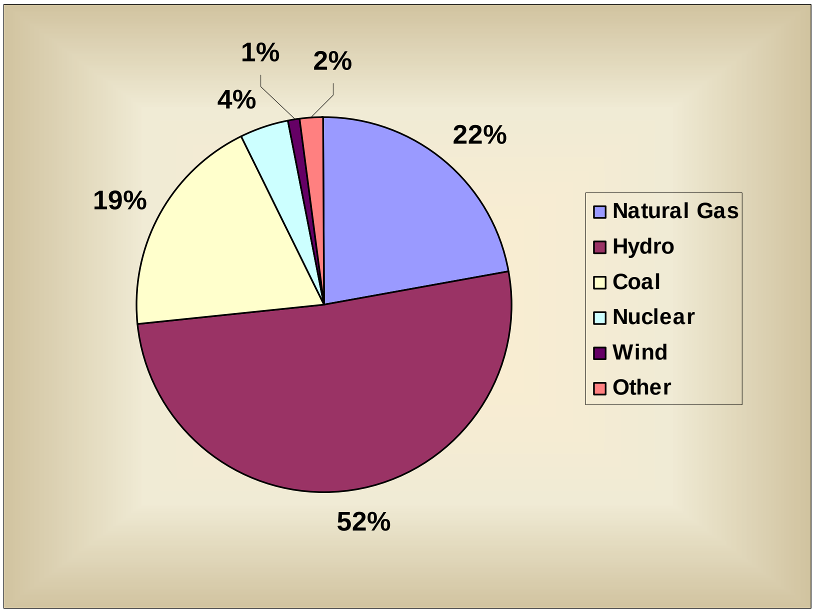

Figure 4: Sources of Pacific Northwest Electrical Energy Generation

Although the traditional indicator of resource needs has been average energy, increasing attention is being paid to the region's capacity to meet various types of peaking requirements. The regional generating capacity, the combined peak generation capability is over 50,000 megawatts; much larger than current winter peak loads. However, two thirds of that capacity is in the hydroelectric system, and the ability of the hydro system to meet high cold weather loads over a sustained period is limited. The sustained peaking capacity[1] of the hydro system, for example, is 5,400 megawatts less than its nameplate capacity.

The region's energy mix has been changing over time. Twenty years before the Northwest Power Act, the region's electrical energy came almost entirely from hydroelectricity. By the time the Act was passed, the region was outgrowing its hydroelectric capability and coal, nuclear, and natural gas generation accounted for a quarter of the electrical energy supply. Currently, these thermal resources account for 45 percent of the region's electrical energy supply. Figure 5 illustrates how the mix of regional electricity generation has changed over time.

Conservation that has been achieved since the Northwest Power Act is also conceptually a part of the region's resource mix although it is not shown in Figures 4 or 5. The Council has estimated, as noted above, that the region has acquired 2,600 average megawatts of end-use conservation through 2002, the equivalent of about 2,800 average megawatts of electricity generation. Approximately 25 percent of the resources added in the Northwest since 1980 have been conservation.

[1] Sustained peaking capacity is typically defined as the maximum amount of energy the hydroelectric system can deliver (on average) over the 50 highest demand hours in the week (generally modeled as 10 hours per day over the weekdays).

Another component of the region's electricity supply is the ability to import electricity from other regions. The region currently has the transmission capability to import up to 6,775 from the South and 3,150 megawatts from the North. This transmission capability is used to provide additional flexibility to electricity supply and mutually beneficial electricity trade with neighboring regions. Except for existing long-term firm contracts, however, the region has not explicitly relied on seasonal power availability in California and our ability to import it over existing transmission interties for resource planning. In actuality, however, some degree of reliance on imports had been part of normal operations for many years.

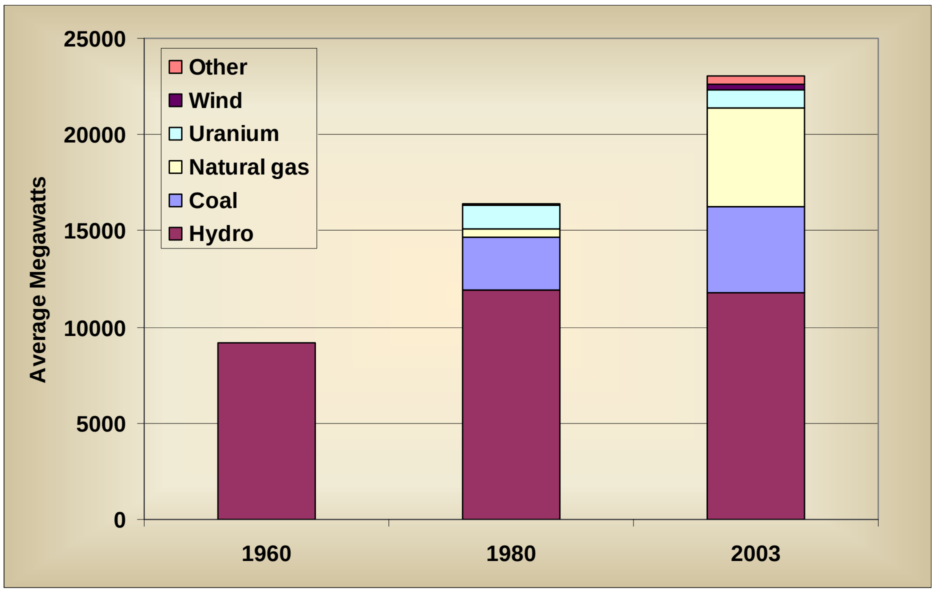

Figure 5: Changing Pacific Northwest Sources Electricity Generation

The region's energy supplies have grown to meet growing electricity demand. The region's electrical energy resources are more diverse now than they were historically. As the resource mix has changed, so has the nature of the risks and uncertainties facing the region. Hydroelectricity still accounts for roughly half of the region's electrical energy supply, but its amount in any given year depends on water conditions. In an average water year, the hydroelectric system can provide about 16,000 average megawatts of electricity. For planning, the region has formally relied on only the 12,000 average megawatts shown in Figure 5, which is the amount of generation ability under the worst historical water conditions (critical water). In a good water year, the hydroelectric system might be able to generate 20,000 average megawatts of electricity. In reality, the region has probably departed informally from critical water standards for a decade or more.

In addition to varying with water conditions, hydroelectric generation has a distinct seasonal pattern that can only be partially managed by the use of reservoir storage. The ability to shape hydro generation to the seasonal load requirements has been reduced by growing fish and wildlife management requirements. The direct service industries, industrial customers served by the Bonneville Power Administration, also contributed to the ability to manage hydro uncertainty through interruption agreements on the top quarter of their electricity use. Most of the direct service industries were aluminum plants, now closed, and they no longer provide that flexibility.

The new thermal generating resources are more predictable in the amounts of electricity they provide, but are more prone to cost uncertainty as their input fuel prices vary. This is especially true of the natural gas-fired generation that has made up most of the recent generation additions. Nuclear and coal plants carry a different kind of risk. Their costs consist primarily of capital costs that must be paid whether they are generating electricity or not, thus they carry a larger financial risk when they are not needed for meeting electricity demand.

Current Load-Resource Balance

On the basis of generation installed in the region, the Pacific Northwest currently has more than enough electricity resources to meet demand. The expected load/resource balance for 2004 is a resource surplus of about 1,000 average megawatts over demand. As recently as 2000, the region had a critical water deficit of about 4,000 average megawatts. When the region experienced poor water conditions in 2000 and 2001, it triggered an electricity crisis affecting the entire West Coast. The crisis was described in the introduction.

Two major factors erased the region's energy deficit: a reduction in demand and the addition of new generating capacity. Demand fell by about 2,800 average megawatts between 2000 and 2003. At the same time new generating resources were added that increased energy capability by about 3,500 average megawatts.

Figure 6 shows average annual load resource balances in the region with critical water conditions under different demand forecast conditions. In the medium case, the surplus lasts until 2012. Given the ability to import energy from the Southwest, this does not necessarily indicate a need, even then, for new regional electricity generation. The picture is very different for the medium-low and medium-high forecasts. The region remains in surplus under medium-low demand growth to 2013 and beyond. However, with medium-high demand growth the region is somewhat deficit throughout the 2004 to 2013 period.

Not all the resources in the region are contractually committed to regional loads. Independent generators own many of these resources. But most are also not committed on a firm basis to loads outside the region. We are assuming that these resources would be available to meet Northwest loads. This implies that sufficient resources exist outside the Northwest to offset any contractual export commitments that these generators may have. This has been a good assumption in most years as California and the Southwest are summer peaking systems that typically have excess capacity available in the winter when Northwest loads are highest. However, the problems experienced in the California market in 2000-2001 were an important exception.

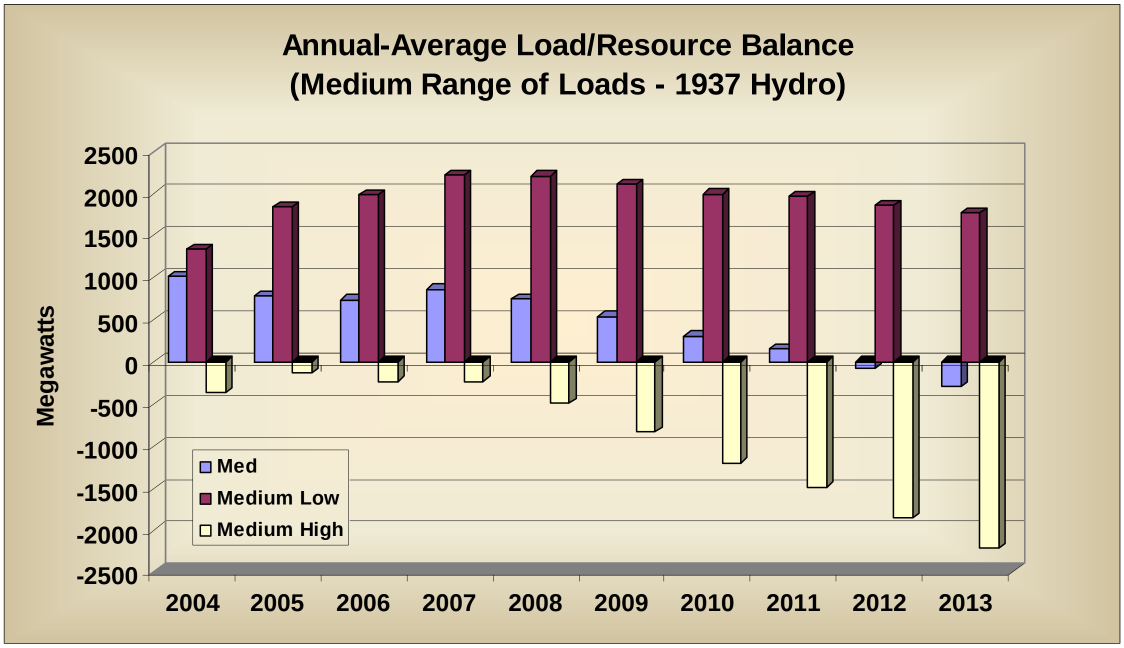

Figure 6: Load Resource Balance with Existing Resources Under Medium-Low, Medium And Medium-High Demand Forecasts

Assessing Future Supply Alternatives

The essence of the power plan is a determination of how future electricity needs should be supplied. The plan relies on analysis and forecasts of alternative generating and conservation technologies and their costs. These analyses and forecasts necessarily reflect the current knowledge of alternative technologies and their costs, but also attempt to project a range of possible future trends.

Natural Gas

Conditions in other energy markets affect both the demand for electricity and the expected cost of electricity. Particularly important in the Pacific Northwest is the cost of natural gas. Natural gas is both the most active competitor to electricity for space and water heating and the fuel source for most recent electricity generation additions. Recently, volatile and increasing natural gas prices have had a significant effect on energy costs in the region.

If natural gas prices remain significantly higher than they were during the 1990s, as the Council's forecast suggests, then coal prices and the costs of renewable generation will become more significant for future electricity generation and its costs. There is still substantial ability among industrial users to switch between oil and natural gas use depending on their relative prices. With growing natural gas price volatility, fuel-switching capability may increase as a way of mitigating vulnerability to periods of high natural gas prices.

Figure 7 shows recent natural gas spot market prices at the national and regional level. National wellhead prices from 2000 to 2003 have averaged $4.06 compared to $1.86 during the 1990s. Natural gas prices in the Pacific Northwest are typically lower than national prices due to proximity to relatively low-cost natural gas supplies in the Western Canada Sedimentary Basin and the U.S. Rocky Mountains. During the 1990s this difference averaged $.51; from 2000 to present it has averaged $.42.

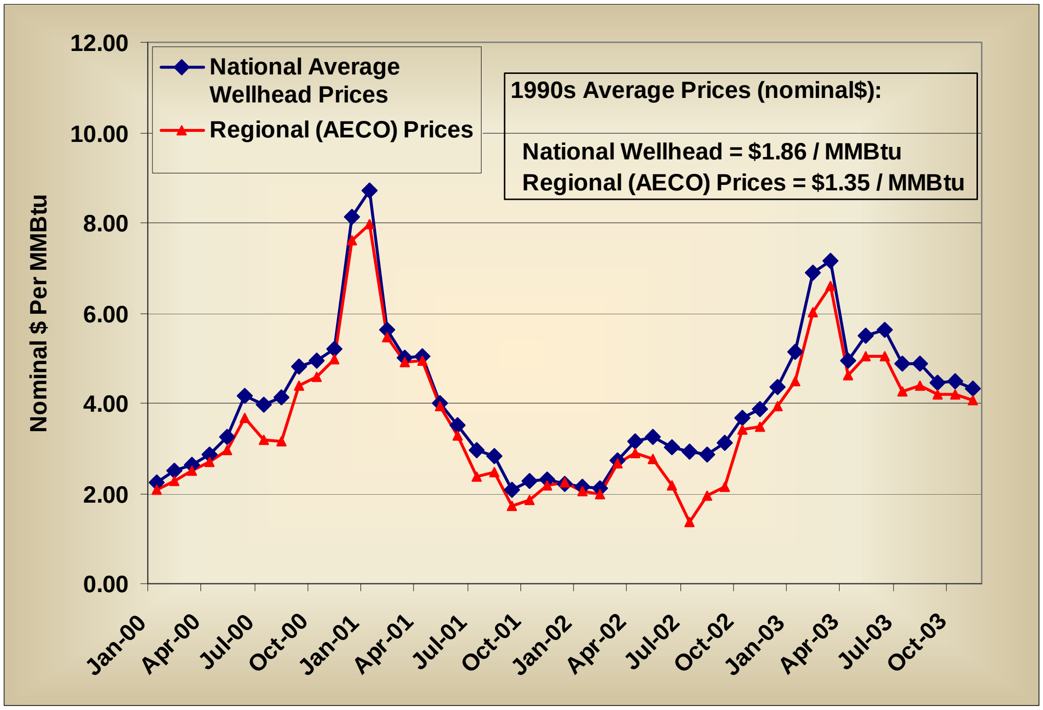

Figure 7: Recent National and Regional Natural Gas Prices

The Council forecasts a range of natural gas prices for use in this draft plan. The medium case assumes that national wellhead natural gas prices will average about $4.00 in 2004 (in year 2000 dollars) and drop to $3.25 in 2005. Prices are then assumed to grow gradually to $3.60 by 2025. The ending prices in 2025 vary from $2.65 in the low to $4.25 in the high. The recent prices and forecasts are shown in Figure 8.

The Council does not expect fuel prices to follow the smooth trends shown in Figure 8. New sources of natural gas supply will need to be developed during the forecast period, including non-conventional supplies (coal bed methane, tight sands, oil shale), increased import capability through liquefied natural gas terminals, and new pipelines to remote sources. As long as these new gas supplies have difficulty keeping up with demand, natural gas prices will be volatile, reacting dramatically to changes in temperature, storage levels and other indicators of changing supply or demand. The draft plan captures the implications of such volatility, as well as the uncertainty in long-term trends represented by the range of natural gas price forecasts.

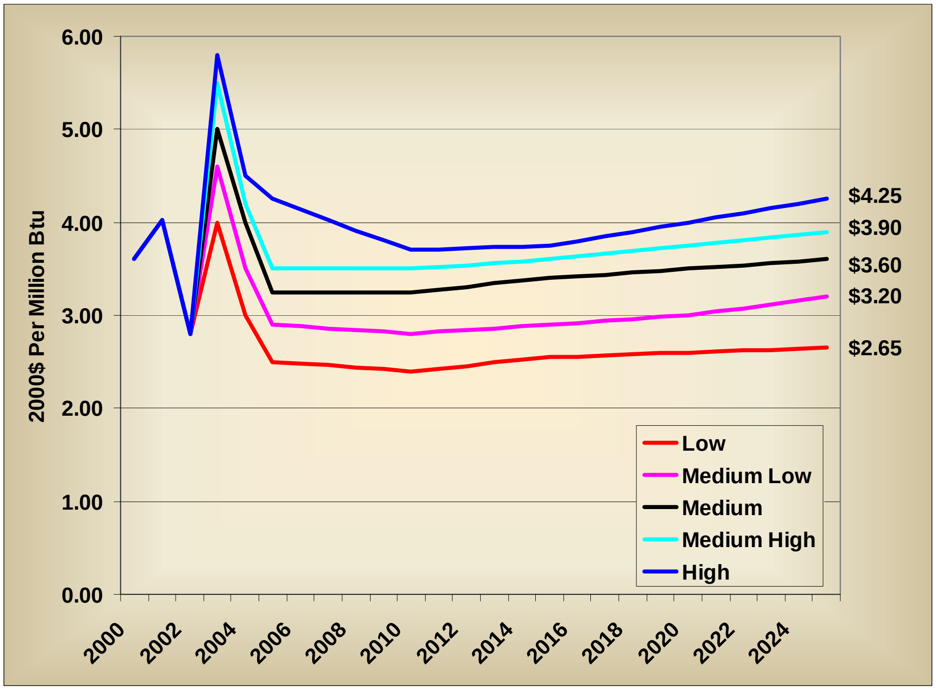

Figure 8: Range of Future Natural Gas Price Forecasts

Coal and Oil

The forecasts of coal and oil prices do not share the much higher price relative to recent historical levels that characterizes the natural gas price forecast. The medium-low to medium-high world oil price forecasts reflect OPEC's stated price target range of $22 to $28 a barrel. The low and high forecasts reflect the possibility of price falling outside that range, but with smaller likelihood. As in the case of natural gas, oil prices are expected to exhibit significant volatility responding to world economic conditions and political developments in the Middle East.

Coal prices are expected to remain relatively stable and, in all but the high case, are projected to decline slightly relative to general inflation although at a much slower rate than in the past. Combined with higher natural gas prices, this will tend to make coal relatively more attractive as a source of electricity generation. However, there remains significant uncertainty about future environmental regulations that might adversely affect coal use. More detail regarding fuel price forecasts appears in Appendix ??

Conservation

The Council considers improved efficiency of electricity use to be a resource for meeting future electricity demand. It is a priority resource in the Northwest Power Act. Conservation potential and cost are assessed by evaluating many individual efficiency improvements in each consuming sector. These individual improvements, or measures, are ordered by increasing cost into a supply curve for conservation. Potential savings from implementing each measure are assessed in terms of technical potential as well as actual expected savings when policies are put in place to implement the measures. Cost-effective conservation measures are determined by comparing their cost per expected megawatt of savings to the cost of avoided electricity generation as measured by the estimated market price of electricity.

Looking back 20 years to the Council's first power plan, the estimated cost-effective conservation available averaged about 3,600 average megawatts, although the amount varied substantially depending on the specific demand forecast. It was expected that about 1,200 megawatts of this potential would be accomplished through consumers' response to changing electricity prices, with 2,500 megawatts to be acquired through utility conservation programs. As noted above, the region has succeeded in acquiring this conservation over the last 20 years. Does this mean there is no further efficiency improvement that is cost effective? No, in fact, the amount of future cost-effective conservation has remained significant in each of the Council's power plan revisions. The current assessment of achievable cost-effective conservation potential in this draft plan, at 2,680 [May have been slightly revised] average megawatts, is not vastly different from the amount in the first power plan.

This is, however, greatly increased from the 1,500 megawatt potential in the Fourth Power Plan. There are two primary reasons for the additional conservation potential in this draft. Most important is the continuing improvement in technology leading to new conservation measures and declining cost for many measures. Especially significant in this plan are improvements in lighting technology for both residential and commercial applications. In addition, the Council has expanded its evaluation of conservation potential in the non-building commercial sector. Significant efficiency gains were found to be cost effective in sewage and water treatment, computer equipment, vending machines, and small AC to DC power converters to name a few. The residential and commercial sector account for about 85 percent of the potential conservation.

The second reason for increased conservation potential is that avoided generating costs are higher due to increased forecasts of natural gas prices. This enables some higher cost conservation measures to become cost effective.

Demand Response Resources

Analysis of the 2000-2001 electricity crisis made it clear that without the ability of electricity use to respond to wholesale electricity market conditions, electricity prices can escalate almost without limit under tight market conditions. This is a condition that particularly characterizes the mixed electricity market that we currently have. Since consumers are not exposed to wholesale price changes in a timely manner, they cannot respond to shortages and wholesale price escalation. This eliminates from electricity markets the automatic stabilization that works in most commodity markets. Combined with the inability to store electricity and the necessity of continuously balancing supply and demand, this makes wholesales electricity markets highly unstable and volatile during tight market conditions.

"Demand response resources" refers to programs whereby consumers can be given an opportunity to reduce electricity consumption when the value of electricity becomes very high. The objective of these programs is to moderate the volatility of electricity prices and to help reduce the expense of providing generation capacity for the most extreme peaks of electricity demand. Such demand reductions in the Pacific Northwest, though not implemented in the most timely manner, probably significantly reduced the length and impact of the 2000 and 2001 electricity shortage. Such programs need to be developed so that they can be implemented quickly, have predictable results, and reduce the negative economic impacts of such consumption reductions.

The Council sees demand response as a key policy for the mixed electricity market that is expected to continue for the foreseeable future. Demand response is different from conservation because it involves interruptions to electricity service as opposed to improved efficiency of use. However, the participation in such programs should be designed to be voluntary for energy consumers. The power plan estimates the value of such programs being in place in the regional power system.

Renewables and Other Resource Options

Renewable resources are also a priority resource in the Northwest Power Act. Like conservation, their potential and cost-effectiveness are sensitive to developing technology and the cost of more traditional generating alternatives. Many of these alternatives remain expensive relative to conservation or fossil fuel-fired generation. Wind energy, however, is becoming more competitive. Its attractiveness is aided by financial incentives, renewable portfolio standards, and green-tag credits. These are assumed to continue in the future, but wind technology improvements and falling cost are also assumed to continue in the future. Renewables have potential risk reduction benefits related to their ability to hedge risks of fuel price volatility and the risks of possible measures to mitigate greenhouse gas emissions.

Distributed generation is a potential future source of electricity. Distributed generation consists of electrical generating units, generally small-scale, located at or near loads. These can take advantage of cogeneration opportunities, offset transmission, distribution and end-use loads and improve reliability. Its cost-effectiveness is more difficult to assess because it depends partly on location specific transmission and/or distribution system constraints and expansion costs. In addition, integration of distributed generation into the electricity grid is relatively new and the problems are not well understood. Nevertheless, like conservation, distributed generation may carry significant cost advantages in specific situations and locations. It may be most important to assure that the operation and management of the electrical generation and transmission system allows opportunities for such resources, provides appropriate price information and does not impose barriers to their development where cost effective.

Projected Wholesale Electricity Prices

Western electricity markets were in chaos between June 2000 and May 2001. Monthly Mid-Columbia heavy load hour spot prices averaged over $238 per megawatt-hour during these 12 months. The prices during this electricity crisis were well described in the introduction to this plan. However, prices dropped rapidly after May 2001 and have been more reflective of generating costs recently. Figure 9 shows average monthly prices during 2003, which averaged $37 per megawatt-hour.

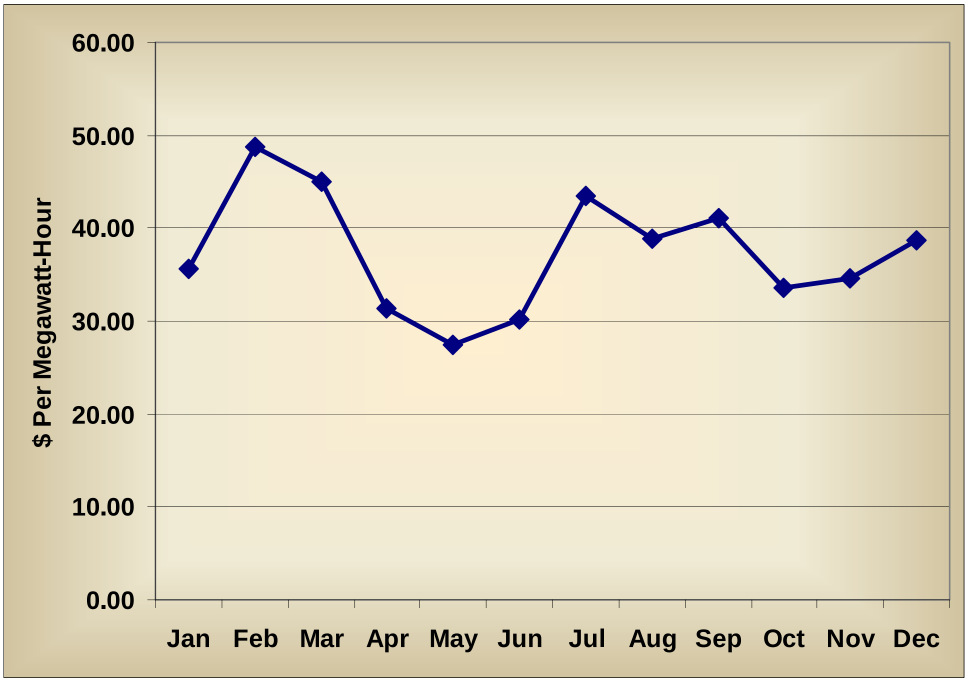

Figure 9: Wholesale Spot Market Electricity Prices at Mid-Columbia Pricing Point: Jan. - Dec. 2003

Forecasts of electricity demand and supply alternatives and their costs, including fuel costs as described above, are used to forecast future wholesale electricity prices at various pricing points in the West. In this discussion, the focus is on wholesale, short-term (spot) market prices at the Mid-Columbia trading hub. These “benchmark” electricity price forecasts are used to help evaluate cost-effective levels of conservation and other resources and serve as the cost of reliance on the wholesale electricity market in the Council’s risk analysis.

Methods

The AURORA™ Electric Market Model is used to estimate Western electricity prices on an hourly basis.[2] Electricity price forecasts are based on the variable cost of the most expensive generating plant, or increment of load curtailment, needed to meet load for each hour of the forecast period. Preparing a forecast is a two-step process. First, a forecast of capacity additions and retirements beyond those currently scheduled is developed using long-term resource optimization logic. This is an iterative process, in which existing resources are retired if forecast market prices are insufficient to meet future maintenance and operation costs. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, maintenance and operation. This step results in the future resource mix depicted in Figures 11 and 12. This resource mix is used as the base resource portfolio for the portfolio risk analyses. The second step is to forecast the dispatch of these resources to obtain an estimate of future power prices. The electricity price forecast, approach, assumptions and associated sensitivity and scenario analyses are fully described in Appendix ??.

[2] The AURORA™ Electricity Market Model was developed and is offered by EPIS, Inc. of West Linn, Oregon. EPIS may be contacted by phone at 503-722-2023 or by e-mail at info@epis.com. The EPIS website is www.epis.com.

As configured by the Council, AURORA simulates dispatch in each of sixteen load-resource zones comprising the Western Electricity Coordinating Council (WECC) electric reliability area. Zones are defined by major transmission constraints and are characterized by forecasted load, existing generating units, scheduled additions and retirements, forecasted fuel prices, load curtailment blocks and a portfolio of new resource options. Transmission interconnections between the zones are characterized by transfer capacity, losses and wheeling costs. Demand within a load-resource zone may be served by native generation, curtailment, or by imports from other load-resource areas if economic, and if transmission transfer capability is available.

Because of run time considerations, the inventory of new generating resource alternatives for capacity expansion runs is limited to resources expected to significantly influence future electricity prices. Alternatives such as gas combined-cycle plants and wind are currently important and likely to remain so. Others, such as new hydropower or biomass, are unlikely to be available in sufficient quantity to influence future power prices. Some, such as solar photovoltaics are not significant at present, but may become major players as costs decline. Finally, some resources, such as gas-fired reciprocating generator sets do not greatly differ from other resources (in this case simple-cycle gas turbines) with respect to their effect on future power prices. With these considerations in mind, the new resources modeled for this forecast included natural gas combined-cycle power plants, two cost levels of wind power, coal-fired steam-electric power plants, natural gas simple-cycle gas turbine generating sets and central-station solar photovoltaic plants. Additional discussion of new generating resource alternatives is provided in Chapter YY.

Base Case Forecast

The "Current Trends" base case forecast is based on the medium load and fuel price forecasts, average hydropower conditions, and current trends with respect to technological development, energy-related policies and other factors affecting the market price of electricity (Table 3). These assumptions and the resulting forecast resource mix are not necessarily "the right things to do", nor necessarily reflect the recommendations of this plan. Instead they represent the direction that the industry appears to be moving at the present time. The final plan will contain one or more price forecasts illustrating the effect of the Council's recommendations on future power prices.

The levelized annual average electricity price at the Mid-Columbia trading hub for 2005 through 2025 is forecast to be $36.10 per megawatt-hour (year 2000 dollars[3]). This forecast is somewhat lower than the preliminary draft forecast released in September 2002 ($37.50/MWh), but considerably higher than the forecast prepared in conjunction with the Council's Adequacy and Reliability Study of February 2000 ($29.80/MWh).

Figure 9 shows forecasted annual average prices for the Mid-Columbia trading hub. The initial years of the forecast conform to historical price behavior. Prices decline from 2000-01 highs, then rise in 2003 as a result of gas prices increases. Prices then decline from 2003 highs as gas prices are forecasted to ease, and rise through 2010 as loads recover and the current capacity surplus is exhausted. Prices are fairly stable through the remainder of the planning period as slowly increasing natural gas prices are offset by improved combined-cycle efficiency and increasingly more cost-effective windpower. Episodes of price excursions resulting from volatility in the gas market or poor hydro conditions cannot be forecast, but are likely to occur during the forecast period.

[3] All prices in this paper are in constant year 2000 dollars unless noted otherwise.

Table 3: Summary of assumptions underlying the Current Trends forecast

Hydropower	Average hydropower conditions
Fuel prices	5th Plan revised draft forecast, Medium case (April 2003)
Loads	5th Plan revised draft sales forecast, Medium case (April 2003)
Existing and planned resources	Resources in service Q1 2003 Additions under construction Q1 2003 Retirements scheduled Q1 2003 75% of state renewable portfolio standard and & system benefit charge target acquisitions are secured 50% of forecast Demand Response potential by 2025.
New resource options (market-driven development)	Gas-fired combined-cycle Wind Coal steam-electric Gas-fired simple-cycle Central-station solar photovoltaics Suspended projects > 25% complete
Inter-regional transmission	2003 WECC path ratings Scheduled upgrades Q1 2003
Climate change response	Gradual enactment of a Oregon-type CO_2 standard, escalating in cost
Renewable resource incentives	Continued federal production tax credit Green tag revenue, escalating in value
Intermittent resource penetration limit	20 - 25% of installed capacity by load-resource area

The annual average prices of Figure 9 conceal significant seasonal price variation that develops as the current capacity surplus declines. Figure 10 illustrates monthly average prices. A strong August peak, driven by summer afternoon air conditioning loads in the Southwest, is fully developed by 2010. As the capacity surplus further declines, the price peak broadens to include July. Northwest market prices track those in the Southwest whenever transfer capacity is available on the Pacific interties. The strong seasonal price peak adds value to summer-peaking resources such as irrigation efficiency improvements. Forecasted daily variation in price is significant as well, with implications for the cost-effectiveness of certain conservation measures. A table of forecasted annual average prices for the Mid-Columbia trading hub and other Northwest pricing points is provided in Appendix ??.

The forecast WECC resource mix associated with the Current Trends forecast is shown in Figure 11. Factors at work from 2005 to 2025 include load growth, increasing natural gas prices, technology improvements, renewable resource incentives and increasing efforts to offset carbon dioxide production. Most existing gas-fired steam-electric capacity is retired over the period and approximately 6,000 megawatts of renewable resources are added as the result of state renewable portfolio standards and system benefit charges. Market-driven resource additions include 37,000 megawatts of combined-cycle plant, 13,000 megawatts of coal capacity, 33,000 megawatts of wind capacity and 3500 megawatts of gas peaking capacity. About 14,000 megawatts of solar photovoltaics capacity are added near the end of the planning period. Not shown in Figure 11 is about 9,000 megawatts of short-term demand response capability assumed to be secured by 2025.

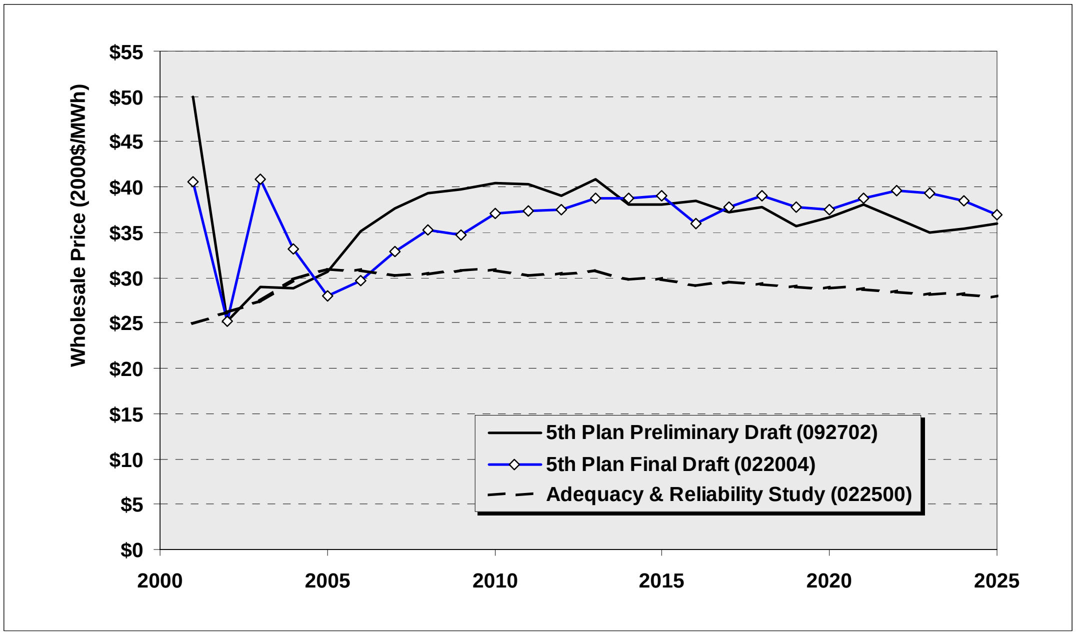

Figure 9: Current and Earlier Base Case Forecasts of Average Annual Wholesale Power Prices and the Mid-Columbia Trading Hub

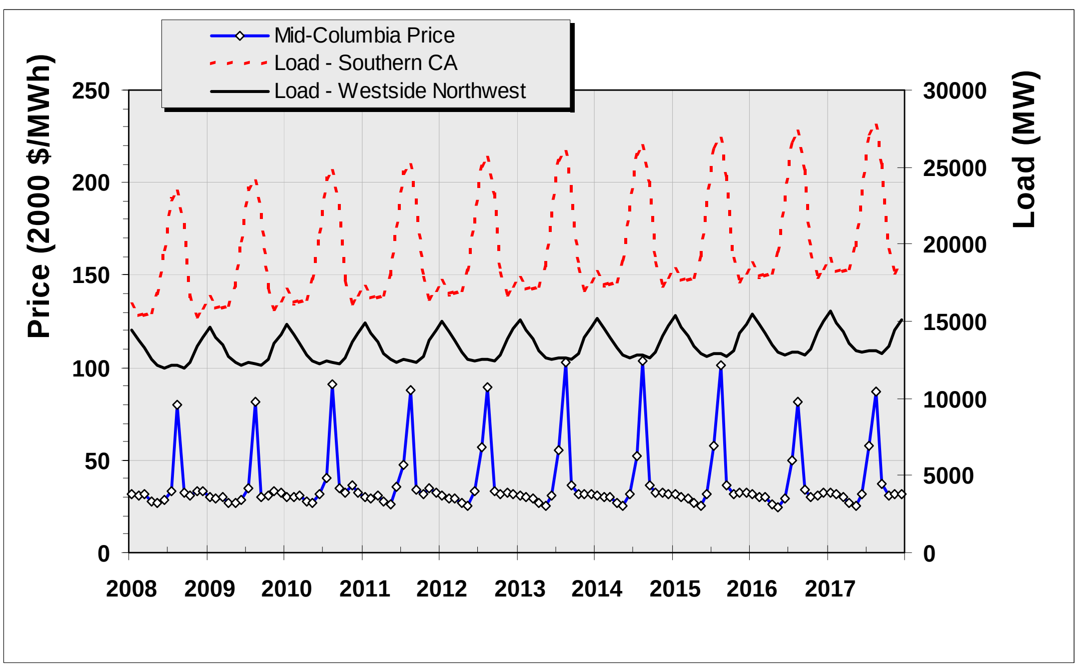

Figure 10: Forecast Monthly Wholesale Mid-Columbia Electricity Prices Compared to Northwest and Southwest Loads

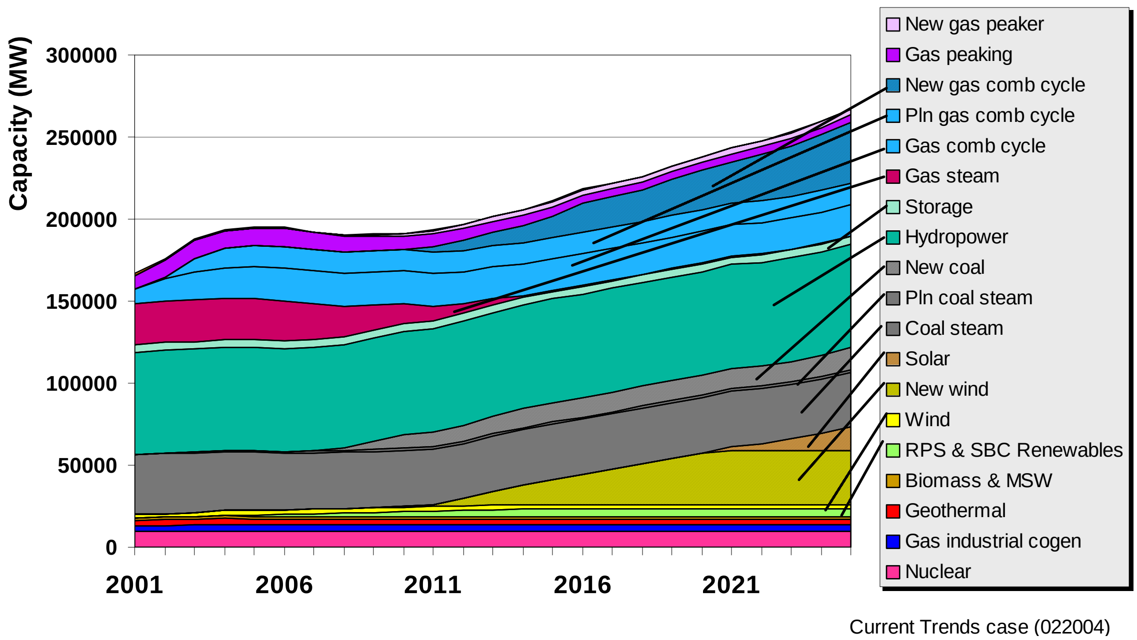

Figure 11: Base Case Forecast WECC Resource Mix

The Northwest resource mix is shown in Figure 12. The (unchanging) hydropower component is omitted from Figure 12 to emphasize other resource changes. About 1,600 megawatts of coal, 7,000 megawatts of wind, 1,200 megawatts of renewable resources (modeled as wind) funded by state system benefit charges and 1,800 megawatts of new combined-cycle capacity are added by 2025. Much of the existing gas peaking capacity is retired. Not shown in the figure is about 1,900 megawatts of short-term demand response capability assumed to be secured by 2025.

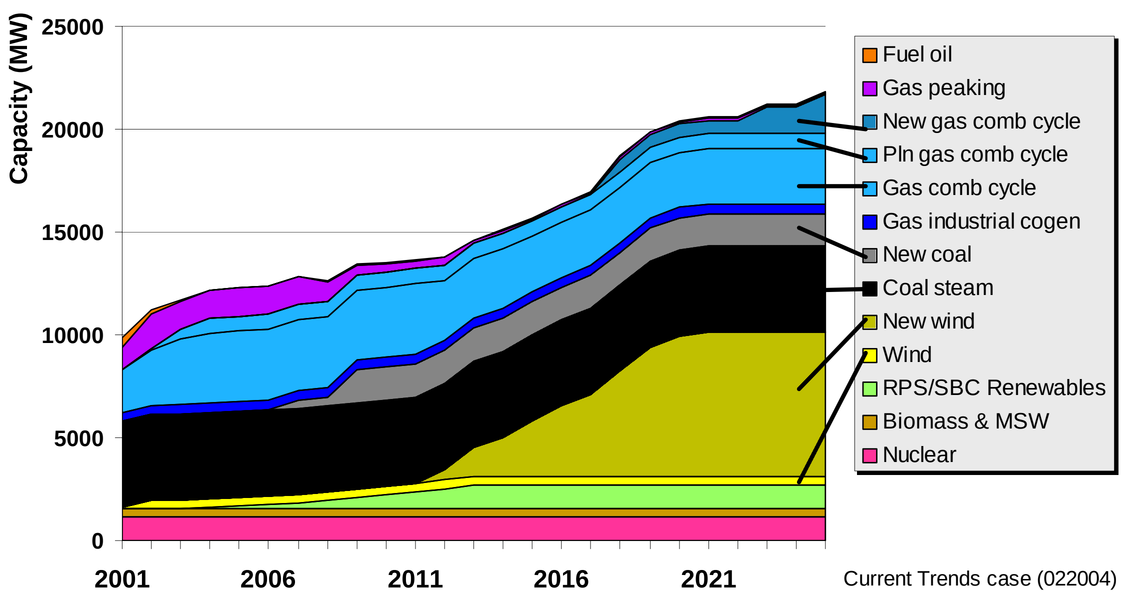

Figure 12: Base Case Forecast of Pacific Northwest Resource Mix (Hydro Omitted)

Other Scenarios

Two additional price forecast scenarios were run to explore the effects of alternative, yet plausible sets of assumptions regarding the future.

Planning Reserves: Capacity-expansion studies using AURORA typically result in low reserve margins. For example, coincident peak hour reserve margins for WECC as a whole in the Current Trends forecast average about 7% in the long-term. Power systems typically maintain 5 to 8 percent additional "Planning margin" as protection against events such as low water years, unexpected rates of load growth and failure to complete projects as scheduled.

A variation of the Current Trends base case was run to create a resource portfolio incorporating a 15% planning margin. The resulting resource mix is illustrated in Figure 13. The horizontal bars depict WECC capacity in-service by major resource type as of 2025. The value at the right end of each bar is the levelized Mid-Columbia price forecasts for that case. In the 15% Planning Reserves case, 2025 wind capacity remains the same as in the base Current Trends case because the available resource is fully developed in each case. Slightly less solar photovoltaics capacity and somewhat more coal capacity is developed in the Planning Reserves scenario. Most of the additional capacity of the planning reserves case is natural gas-fired, consisting of new peaking capacity, and existing steam and gas turbine generators that are retired in the base case. If dispatched using the Current Trends assumptions, the additional capacity lowers the levelized Mid-Columbia prices to $29.10/MWh. However, inclusion of the additional fixed costs of the added increment of capacity raises prices about 10% over the base case to $39.80/MWh. This increment represents the cost of insuring against long-term planning risks. Additional discussion of this and the other scenarios and sensitivity cases is provided in Appendix ??.

Business-as-Usual: Some commentors have suggested that the base case assumptions regarding future natural gas prices, efforts to secure demand reduction capability, renewable resource development incentives and efforts to reduce CO2 production are too optimistic. The following changes were combined into a "Business-as-Usual" scenario to explore the effect on the electricity price forecast.

- Extended high natural gas prices
- CO2 offsets limited to an Oregon-type CO2 standard for Oregon and Washington by 2004 and for California, British Columbia and Alberta by 2007.
- Lower green tag value.
- Lower demand response capability.
- Near-term renewal followed by phase-out of the renewable energy production tax credit.
- Less effective renewable portfolio standard and system benefit charge acquisitions.
- The current FERC price cap of $250 throughout the forecast period.

The effect on resource composition and environmental effects is more pronounced than on the price forecast. The Mid-Columbia electricity price forecast declines 1% to $35.70 and seasonal peak prices are reduced. . WECC coal consumption over the forecast period is 15% higher and gas use 19% lower. Wind and solar represent 12% of WECC capacity in 2025 compared to 20% in the base case. Carbon dioxide production increases 6% over the planning period..

Sensitivity Analyses

Sensitivity analyses were run on several assumptions to explore the effect of outcomes other than those assumed in the base case forecast. The 2025 WECC resource mix and levelized Mid-Columbia price forecasts resulting from the sensitivity cases are shown in Figure 13. Forecast electricity prices show the greatest sensitivity to fuel prices, reserve requirements and carbon dioxide control requirements. Additional discussion of the sensitivity analyses is provided in Appendix ??.

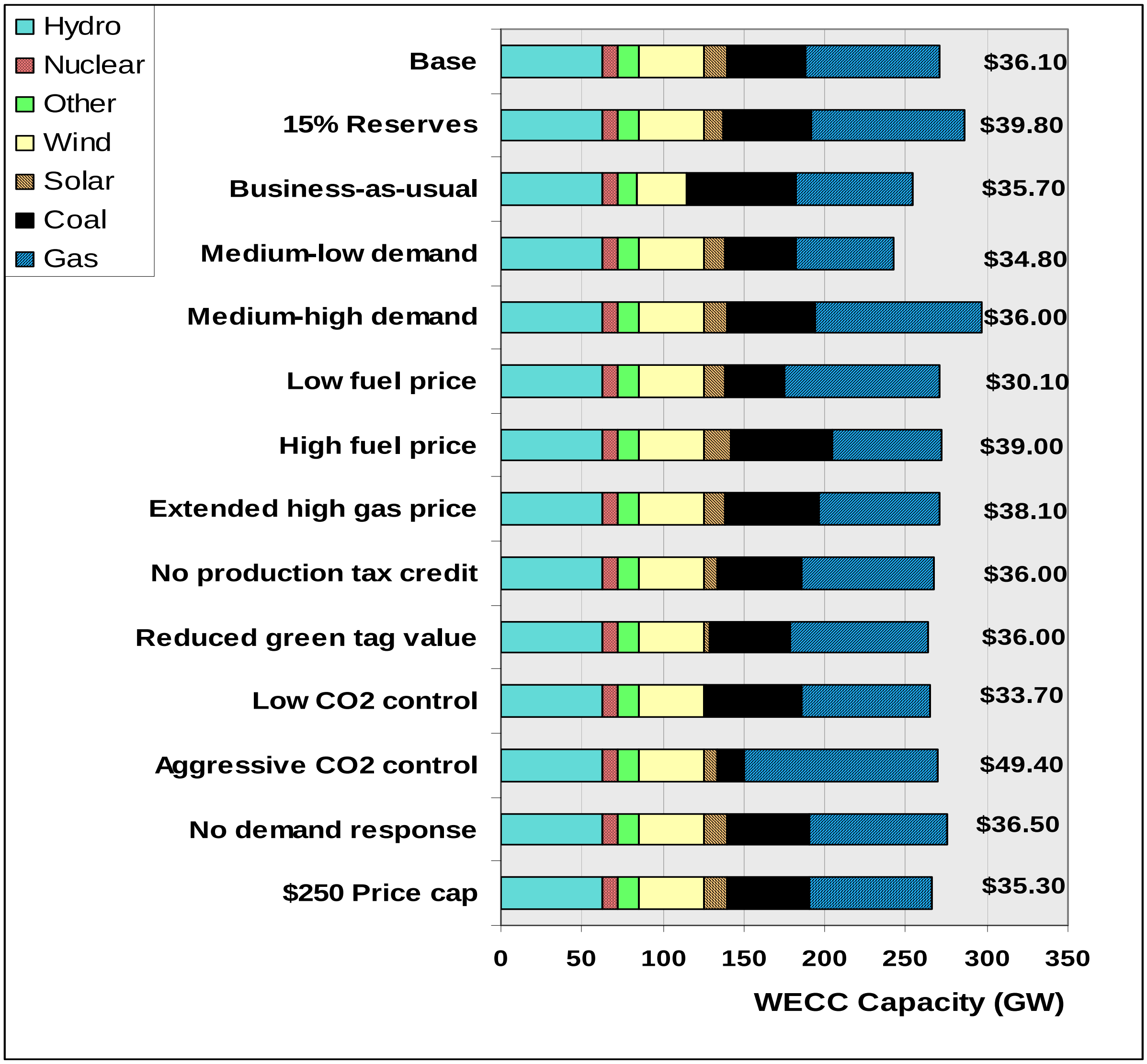

Figure 13: Scenario and Case Study Resource Mix and Mid-Columbia Price Forecasts

Institutional and Policy Status

Electricity policy and institutional conditions are as important for the achievement of the energy goals of the Northwest Power Act as the demand and supply of electricity. The electricity crisis of 2000 and 2001 was a result of both inadequate electricity supplies and poorly organized and regulated wholesale electricity markets. The shortage of electricity supplies has been addressed for the time being, but the wholesale electricity market structure remains uncertain and fragmented. Basic issues of transmission system operation and planning have not been resolved.

Many basic responsibilities for resource adequacy and transmission system capacity expansion remain unclear. In addition, many participants in the independent power producer sector have been financially weakened, or bankrupt, by the electricity crisis and its fallout.

The development of a substantial electricity surplus has given the region a window of opportunity to address these issues. Currently, the state-regulated electricity distribution and sales sector, the federally regulated transmission system, and the competitive wholesale electricity market do not always operate smoothly together. Their individual limits and interactions are not well defined and are inconsistent among the states in the region and in the West. There are a number of issues that need to be worked out, including:

- The region needs to address growing problems in the management, operation, planning and expansion of the transmission system.
- A more transparent wholesale power market structure needs to be developed and operated in concert with the transmission system.
- Accountability for monitoring wholesale electricity and transmission markets is needed along with improved data for timely market assessment.
- It is important to facilitate demand that is responsive to wholesale market conditions, whether through retail access, electricity pricing schemes, or utility demand management programs.
- Bonneville's role in a modern electricity market needs to be defined, including a lasting settlement of the residential exchange and an agreement on Bonneville's role in meeting growing loads beyond its current Federal Base System resources.
- Changing demands and resource adequacy need to be monitored carefully until it is well established that the mixed regulated and competitive electricity system will result in enough capability to reliably meet loads.

Other Considerations in Developing a Resource Portfolio

There are a number of considerations that enter into developing the power plan resource recommendations. The objective is to minimize the expected cost of providing electricity services, such as lighting, water heating, refrigeration, or space conditioning. The focus on electricity services, of course, brings efficiency changes into the mix. The term "expected cost" recognizes that the future is uncertain and that there is volatility in energy prices. A lowest expected cost resource plan must consider resources and strategies that are more robust in the face of changing or volatile conditions. The Northwest Power Act also requires that the Council include in its costs environmental costs associated with resource alternatives. So there are three major concerns in developing the power plan: the cost of alternative resources, the ability to address significant risks, and the effects on the environment, including fish and wildlife. The direct costs of resources were addressed above.

Environmental Effects

Environmental costs come into consideration in a number of ways as we look forward . Of course the cost of currently required environmental controls on electric generating plants are included in the direct cost of each alternative generating technology. The plan must also consider, however, the remaining emissions from electricity generation. Quantifying the environmental effects and costs of these emissions is difficult, but the various models used by the

Council to assess electricity generation explicitly estimate the amount of emissions. Environmental effects that are not addressed by current regulations may also carry the potential for future regulation. A primary example of this is CO_2. Several states are implementing CO_2 mitigation requirements. The plan assumes that other states will move forward with similar requirements, which increases the cost of building power plants that emit CO_2. Although current U.S. policy stresses voluntary response to climate change, the growing consensus regarding the existence of climate change and its causal factors suggests the potential for federal regulations or CO_2 taxes as global climate change policies evolve over time. Global climate change may also have an impact on the amount and timing of hydroelectric generation in the region. These are risks that are assessed in the analysis.

The interactions between the power system and anadromous fish policy are a key issue for the Council to address in its power plan and fish and wildlife program. Changing fish and wildlife requirements have had a substantial effect on the capability of the hydroelectric system in the region. In 2001, the region saw that an inadequate supply of electricity could adversely affect the ability to carry out fish and wildlife operations. In addition, inadequate power supplies can have a significant adverse effect on electricity prices and reliability of service. An important issue for this power plan is what determines an adequate power supply and how that supply can be assured in a mixed electricity system. And further, what is an equitable degree of reliability for both electricity and fish and wildlife operations?

Risk and Uncertainty

The Council's first power plan broke new ground in dealing with the uncertainties facing a twenty-year power plan. The plan acknowledged that future electricity demand, fuel prices and water conditions are highly uncertain and included strategies to reduce the errors that could result from unexpected changes in future conditions. Over time, the Council has refined its approaches to evaluating the effects of such uncertainties. With this power plan, we have further refined the consideration of uncertainty to include an analysis of volatility of demand and of electricity and other fuel prices.

With the development of more competitive wholesale markets for natural gas and electricity, volatility has become an important issue. Unexpectedly large price increases and decreases in recent years have demonstrated the vulnerability of the region to price volatility. Better developed and structured energy markets can help reduce vulnerability to this volatility over time, but various types of electricity resources can also help mitigate these risks.

There are of course different types of risks that the region faces. Volatility risk of fuel prices is one. Resources based on wind, conservation, coal, or nuclear are less exposed to natural gas price volatility for example. However, these resources may carry more capital risk. Resources that have a large proportion of fixed costs carry more significant capital risk. This risk is a result of changing demand growth or just demand variations due to weather or business cycles. These resources' costs do not vary a great deal, even if they turn out not to be needed. The dramatic price increases the region experienced around 1980 were a good example of the impacts of capital risk. Large amounts of money were invested in developing nuclear generating plants, most of which turned out not to be needed. Shorter lead times and modular, smaller unit size of power plants help reduce these risks. These types of risk issues were well addressed in the Council's previous plans.

However, an advantage of more capital-intensive resources lies in reducing exposure to price volatility. This power plan has been designed to better address this risk through the development of a new portfolio risk model, OLIVIA. This model helps quantify the value of resources that reduce exposure to volatile energy prices, along with longer-term uncertainty in demand and energy prices.

Summary

When the Council developed its first power plan, the region had just experienced a large price increase and a significant electricity surplus was developing. These are conditions that again face the region as the Council develops its 5th power plan. Demand has been reduced significantly in response to the most recent electricity price increases, and forecasts of future demand growth are lower. New generating resources added in response to the 2000-2001 electricity crisis are the other contributor to the current surplus.

The natural gas price forecasts are higher, and also more volatile than in the last power plan. As a result, natural gas-fired generation alternatives, which dominated new capacity for the last several years, are beginning to loose some of their attractiveness. The relative cost-effectiveness of coal and renewables have increased and may offer a hedge against the effects of volatile of natural gas prices on electricity costs. Conservation potential has increased reflecting technological improvements and higher cost of electricity generation. In a mixed market, the ability to adjust electricity demand to changing conditions is needed to help reduce electric price volatility. Developing this demand response resource may be necessary for a well-functioning mixed electricity market.

The region faces the same uncertainties about the future that it has addressed in past power plans; economic and electricity demand growth, fuel and electricity prices, environmental policy, and hydroelectric conditions. However, electricity and fuel prices have also become more volatile at the wholesale level creating different risks that also need to be addressed in deciding on the most cost-effective resource plan.

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Demand Response (Section of Chapter 3 "Resource alternatives and Characteristics")

What is Demand Response?

Demand response is a change in demand for electricity corresponding to a change in the power system's cost of electricity. The problem is that while the region's electricity supply is generally responsive to conditions in wholesale power markets, its electricity demand is not. This situation has a number of adverse effects. It's widely recognized as one of the factors contributing to the high and volatile electricity prices experienced on the West Coast in 2000-2001.

How did this situation arise? As described earlier, the electricity market is currently a mix of competition and regulation. Producers of electricity, who sell into the competitive wholesale market, generally see prices that reflect the marginal cost of production. When supplies are short, prices rise and producers expand supply. In the short-term, supply expands through operation of more expensive units. In the long-term, supply expands through the building of new power plants. When supplies are ample, prices moderate, and producers cut back the operation of their most expensive units and review their plans to invest in new generating units.

But most consumers of electricity see retail market prices that are set by regulatory processes. These retail prices do not follow wholesale market prices except over the long run. It may take a year or more for high wholesale prices to be reflected in retail consumer prices. The good news is that retail customers are buffered from the volatility of the wholesale market. The bad news is that retail customers have little immediate incentive to respond to shortages and high wholesale prices (e.g. caused by extraordinary weather, poor hydro conditions, by temporary generating or transmission outages or even market manipulations) by reducing demand for electricity.

In the absence of such response, overall system costs are increased. More expensive generators are dispatched and eventually, when there are no additional supplies available, prices can become extremely high as load serving entities bid against one another for power. As the experience of the last couple of years has shown, higher costs to load-serving entities eventually make their way into retail rates and customers' bills. Without demand response,[1] the electricity market lacks one of the mechanisms that moderate prices in most other markets.

In the traditional world of regulated monopoly utilities, inaccurate retail market signals led to a power system that was inefficient but tolerable. Without much demand response, we probably built more generation, transmission and distribution facilities than would have been necessary otherwise. However, utilities were able to build the extra facilities, recover their costs and make returns on their investments. The lights stayed on, but average costs were higher than they needed to be. Even in that world demand response would have offered cost savings, by reducing the need for generating and distribution capacity that was used only rarely.

[1] In fact we have had some limited demand response mechanisms in the past. For example, in the past Bonneville had the right in contracts with the Direct Service Industries to reduce power deliveries under certain conditions. However, under current contracts this right is much more limited. The significance of this right is further diminished if DSI load declines in the long term, which seems quite possible.

But in the electricity industry we have now, and many believe we will continue to have in the future, the potential benefits of demand response are even greater. We now rely on a mix of regulated and unregulated power producers to build many new generating plants. The unregulated producers have no obligation to build, and no assurance of making a return on investment. Regulated producers, too, may regard construction of a new generating plant as a risky investment because of uncertainty regarding their ability to recover costs for regulatory and other reasons. There is no guarantee that either group will find it worthwhile to build to the same reserve margins as we have enjoyed in the past.

The region needs to maintain the reliability of the system and moderate the volatility of wholesale prices, without giving up the potential benefits of a competitive wholesale market. In our current situation, demand response can reduce the overall cost of the system, and play a critical role in ensuring reliability and price stability as well.

How is Demand Response Different from Conservation?

The distinction between "demand response" and "conservation." needs to be clear. "Conservation," as the Council uses the term, is improvement in efficiency that reduces electricity use while providing an unchanged level of service (e.g. a warm house in winter, cold drinks, light on the desktop). "Demand response," as the term is used here, is a change in the service (level, quality or timing) that is chosen voluntarily by the consumer, which reduces electricity use or shifts it to a different time. If the change in service were imposed on the consumer involuntarily it would be "curtailment" and it would be evidence of an inadequate or unreliable power system.

Demand response could result from rescheduling an industrial customer's production, resetting a commercial customer's heating system thermostat, or a utility's direct control of a residential customer's water heater. Demand response could also be a customer's substitution of self-generated electricity for electricity provided by the power system (e.g. the use of a backup generator for a few hours at the system's peak load).

There is an important implication of the difference between demand response and conservation. Since conservation leaves service unchanged, the costs of alternative ways of providing the service can be compared (e.g. conservation and generation) and a cost-effective level of conservation in kilowatt-hours estimated. The estimate will be somewhat uncertain because of the quality of data, but the conceptual process is straightforward -- that is, start with the cheapest conservation measures and add more measures until saving another kilowatt-hour costs as much as generating and delivering another kilowatt-hour. The total conservation measures at that point represent the cost-effective level of conservation. The Council's plans have used this level as the basis for efficiency standards and implementation targets.

But this approach can't be used to set a kilowatt-hour target for demand response. To estimate a cost-effective level of demand response in kilowatt-hours would require putting a value on the changes in service levels for the whole range of services that might be affected, which is unfeasible.[2] But it is reasonable to assume that each consumer's choice of service level is best for him given the prices he faces, and would be best for the region as well if the consumer saw

[2] The cost of a changed level of service can be calculated, but to calculate the value it would be necessary to see into each consumer's head.

the region's cost of electricity. Instead of a policy goal specified in kilowatt-hours, we can adopt a goal of identifying incentive mechanisms (e.g. prices paid or payments received) that will lead each consumer's chosen level of service to be best for the region as well. To the extent consumers see these incentives, their demand response to changing conditions will be appropriate for them and for the region as a whole.

There are a number of approaches available to develop greater demand response, each with its own advantages and disadvantages. No one of these mechanisms will be the best for every situation – it seems more likely that some combination of mechanisms will be a sensible strategy, particularly while the region is still learning about their strengths and weaknesses. At the most general level, the approaches can be categorized as price mechanisms and payments for reduced demands. This chapter examines these approaches very briefly, with more detailed examination in Appendix X.

Price Mechanisms

Real-time prices

The goal of price mechanisms is the reflection of actual marginal costs of electricity production and delivery, in retail customers' *marginal* consumption decisions. One variation of such mechanisms is "real-time prices" -- prices based on the marginal cost of providing electricity for each hour. This does not mean that every kilowatt-hour customers use needs to be priced at marginal cost. But it does mean that consumers need to face the same costs as the power system for their *marginal* use. The "two-part" real-time prices used by Georgia Power and Duke Power provide the needed marginal cost signal without charging real-time prices for all usage. The "two-part" tariff charges customers the traditional average-cost based rate for the customer's typical usage, and applies real-time prices to deviations from the typical usage level.

Real-time prices offer significant advantages, including low transaction costs, broad reach, and a very close match of market conditions and customer incentives. Real-time prices also face significant disadvantages, including a requirement of more sophisticated metering and communication equipment than most customers[3] have now, and concern about the volatility and fairness of real-time prices. Real-time prices have not been widely adopted as yet. Because of their problems (more detail in Appendix X), the pace of future adoption may be gradual at best.

Time-of-use prices

"Time-of-use prices" -- prices that vary with time of day, day of the week or seasonally -- could be viewed as an approximation of real-time prices. Time-of-use prices are set a year or more ahead and are generally based on the expected average costs of the pricing interval (e.g. 6 a.m. to 10 a.m. and 5 p.m. to 8 p.m. winter weekdays). Time-of-use prices have many of the same metering requirements as real-time prices. Compared to real-time prices, they have the advantage of more predictable bills and they do not require the same ability to communicate constantly changing prices. On the other hand, time-of-use prices cannot communicate the effects of real-time events on the cost to the system of providing electricity. Compared to real-

[3] Although many large customers already have the metering equipment.

time prices, time-of-use prices trade reduced efficiency in price signals for greater acceptability to customers and regulators, but have nonetheless achieved only limited adoption as yet.

"Critical peak pricing" is a variant of time-of-use pricing that could be characterized as a hybrid of time-of-use and real-time pricing. This variant leaves prices at preset levels, but sets the price of a small number of hours (e.g. 1 percent or 87 hours per year) at a relatively high price (e.g. 4-5 times average price). The hours these prices apply to are not set until conditions warrant, and customers are notified 24 to 48 hours in advance. Utilities are able to match the timing of highest-price periods to the timing of shortages as they develop, providing improved incentives for demand response at times when it is most valuable.

Payments for reductions

Given the obstacles to widespread adoption of pricing mechanisms, utilities have set up alternative ways to encourage load reductions when supplies are tight. These alternatives offer customers payments for reducing their demand for electricity. In contrast to price mechanisms, which vary the cost of electricity to customers, these offers present the customers with varying prices they can receive as "sellers." Arrangements can vary widely in the degree of control given to the utility in exercising the demand reduction, and in the demand reduction's required duration.

Short-term buybacks

Short-term programs are primarily directed at reducing system peak demand (e.g. by reducing loads on a hot August afternoon or a cold January morning). The total amount of electricity used may not decrease, and may even increase in some cases, but the overall cost of service is reduced mostly because of reduced investment in generators and the moderating effect on market prices. Short-term programs can be expected to be exercised and have value in most years, even when overall supplies of energy are adequate.

Utility payment for load reductions

One variant of this approach is a utility offer of compensation for short-term demand reduction (e.g. for a 4-hour period the next day), giving the customer the choice whether or not to accept the offer and reduce load. Generally the customer is not penalized for not responding to the offer, but if the customer accepts the offer there is usually a penalty if the load reduction isn't delivered. Other variations of this approach are described in Appendix X.

Such programs require that customers have meters that can measure the usage during buyback periods. The programs also require that the utility and customer agree on a base level of electricity use from which reductions will be credited. The base level is relatively easy to set for those industrial customers whose use is usually quite constant. It's more difficult to agree on base levels for other customers, whose "normal" use is more variable because of weather or other unpredictable influences.

Demand side reserves

Another mechanism for achieving demand response is "demand side reserves," which can be characterized as options for buybacks. The power system needs reserve resources to respond to unexpected problems (e.g. a generator outage or surge in demand) on short notice. Traditionally these resources were generating resources owned by the utility, but increasingly other parties provide reserves through contracts or an “ancillary services” market. In such cases, the reserves are paid for standing ready to run and usually receive additional payment for the energy produced if they are actually run.

The capacity to reduce load can provide much the same reserve service as the capacity to generate. The price at which the customer is willing to reduce load, and other conditions of participation (e.g. how much notice the customer requires, maximum and/or minimum periods of reduction) will vary from customer to customer. In principle, customers could offer a differing amount of reserve each day depending on their business situation.

The metering and communication equipment requirements, and the need for an agreed-upon base level of use, are essentially the same for demand side reserve participants as for short-term buyback participants. Compared to stand-alone buyback programs, demand side reserve programs may have an advantage to the extent that they can be added to an existing ancillary services market.

Payments for reductions -- interruptible contracts

Interruptible contracts give the utility the right to interrupt a customer’s service under certain conditions, usually in exchange for a reduced price of electricity. Utilities have negotiated interruptible contracts with some customers for many years. An important example of these contracts was Bonneville Power Administration’s arrangement with the Direct Service Industries, which allowed BPA to interrupt portions of the DSI load under various conditions.

In the past, these contracts have usually been used to improve reliability by allowing the utility to cut some loads rather than suffer the collapse of the whole system. In practice, service was rarely interrupted. Now these contracts can be seen as an available response to price conditions as well as to reliability threats. We can expect that participants and utilities will pay close attention to the frequency and conditions of interruption in future contracts, and we can imagine a utility having a range of contract terms to meet the needs of different customers.

Payments for reductions -- direct control

A particularly useful form of interruptible contract gives direct control of load to the utility. Part of BPA’s historical interruption rights for DSI loads was under BPA direct control. Not all customers can afford to grant such control to the utility. Of those who can, some may only be willing to grant control over part of their loads. Direct control is more valuable to the utility, however, since it can have more confidence that loads will be reduced when needed, and on shorter notice. The adoption of advanced metering and other technologies can be expected to facilitate the use of direct control.

Longer-term buybacks

Longer-term reductions in load, from buybacks or other incentives, are uncommon in most parts of the world but have been a useful option in the Pacific Northwest, given the year to year variability of hydroelectric production. Such programs, in contrast to short-term buybacks, generally result in an overall reduction of electricity use. They are appropriate when there is an overall shortage of electricity, rather than a shortage in peak generating capacity.

Most utility systems, comprising mostly thermal generating plants, hardly ever face this situation. The Pacific Northwest, however, relies on hydroelectric generating plants for about two-thirds of its electricity. In a bad water year we can find ourselves with generating capacity adequate for our peak hours, but without enough water (fuel) to provide the total electricity needed over the whole year.

This was the situation in 2000-2001, an unusually bad supply situation for our region. The longer-term buybacks that utilities negotiated with their customers were reasonable and useful responses to the situation. Even though these longer-term buybacks might not be used often, there will be other bad water years in the future, and it's prudent to preserve long-term buybacks as an option for those years. Most of the long-term buybacks in 2000 and 2001 were with aluminum smelters. If, as seems likely, much of than capacity does not resume operation, aluminum smelters would no longer be as significant a source for long-term buybacks. However, there are some other activities that could also be sources for long-term buy-backs.

Relative Advantages of Price Mechanisms and Payment for Reductions

Generally, buybacks avoid some of the problems of price mechanisms, and they have been successful in achieving significant demand response. Utilities have been able to identify and reach contract agreements with many candidates who have the necessary metering and communication capability. The notification, bidding and confirmation processes have worked. Utilities have achieved short-term load reductions of over 200 MW. Longer-term reductions of up to 1,500 MW were achieved in 2001 when the focus changed from short-term capacity shortages to longer-term energy shortages because of poor water conditions.

But buybacks have limitations relative to price mechanisms, even though the marginal incentives for customers to reduce load should be equivalent in principle. Buybacks generally impose transaction costs by requiring agreement on base levels of use, contracts, notification, and explicit compensation. The transaction costs mean that they tend to be offered to larger customers or easily organized groups; significant numbers of customers are left out.

Transaction costs also mean that some marginally economic opportunities will be missed. There may be times when market prices are high enough to justify some reduction in load, but not high enough to justify incurring the additional transaction cost of a buyback.

Potential benefits of demand response

The benefits of demand response depend on: 1) the cost avoided by an incremental megawatt-hour of demand response, 2) the total amount of demand response that can be achieved, and 3) the cost of achieving that amount of demand response. This section will describe approaches to estimating the first two factors. While experience with the cost of achieving demand response is beginning to accumulate, it is not yet practical to translate that experience into a "supply curve" of demand response.

Avoided cost

The cost avoided by an increment of demand reduction is the cost of generating and delivering the extra electricity that would have been needed otherwise. The avoided cost is the value of demand reduction to the power system. The system could afford to pay up to the avoided cost for demand reduction and still reduce the system's total cost.

It's important to understand that the short-run avoided cost can be substantially different than the long-run avoided cost. In the short run the power system may have adequate peak capacity, so that the cost of meeting peak load is simply operating the existing generators and using the existing transmission and distribution system to deliver the energy. In the long run, with growing demand for electricity, the cost of meeting peak also includes the construction and operation of new generating plants and perhaps the expansion of the transmission and distribution system. These extra construction costs can increase avoided cost by multiples of five to 20. The real value of demand response is in avoiding construction of unnecessary generators in the long run. Accordingly, this plan is concerned with long-term avoided cost.[4]

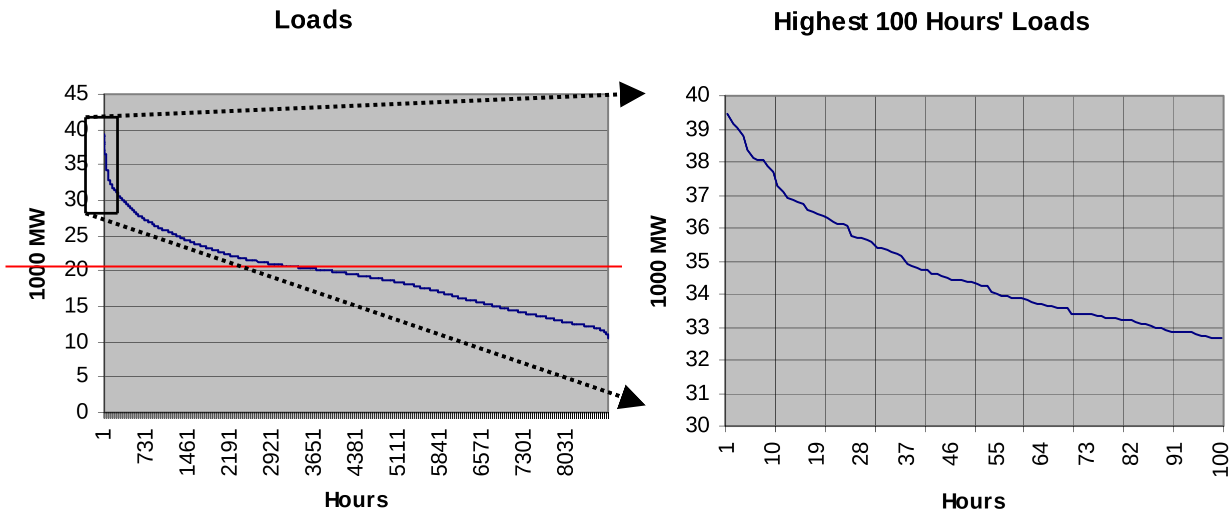
The avoided cost varies widely across the hours of the year as supply and demand for electricity are affected by season, weather and other conditions. The avoided costs will be highest when demand is highest and/or supply is tightest. Estimates of these costs depend on assumptions regarding availability of imports, the degree of flexibility available in the hydroelectric system, the cost of peaking generators, and others.

Council staff have made preliminary estimates of avoided costs that are described in more detail in Section ??. These estimates are substantially higher than the rates paid by most retail customers, which are based on average costs. Retail rates vary by utility but average about $60/MWh over the Pacific Northwest. To the extent that avoided costs and retail rates diverge, retail customers lack incentive to adjust their electricity usage appropriately, and demand response programs are worth pursuing.

The following will be incorporated into the Analysis, Conclusions and Recommendations Section on completion of the portfolio analysis

~~Avoided costs were estimated using two contrasting approaches (see Appendix X for detailed description of these estimates). Both approaches focus on the costs of meeting peak loads of a few hours' duration ("capacity problems").~~

[4] In some cases costs of construction of distribution and/or transmission could also be avoided by demand response. These costs are location specific and are not included in these avoided cost estimates. If it were possible to include distribution and transmission in the calculations avoided costs would be higher.



~~**Figure XX**~~

~~Approach 1. The first approach is to estimate the avoided cost of serving the peak loads of a power system served entirely by its own thermal generation, with loads distributed through the year similarly to the Pacific Northwest's loads. By arranging hourly loads from highest to lowest, a "load duration curve" is created -- shown on the left in Figure XX. The highest 100 hours are highlighted in the segment on the load duration curve shown on the right in the figure. The load in the highest hour is about 39,500 MW, while the load in the 10th highest hour is about 37,800 MW. In other words, about 1,700 MW of generating capacity are needed to meet loads that occur no more than 10 hours in an average year. The cost of building and operating a peaking generator for only 10 hours a year would be $6,489/MWh ($6.49/kWh) for duct burner attachments on combined cycle combustion turbines, and $11,442/MWh ($11.44/kWh) for simple cycle combustion turbines.~~

~~Per megawatt-hour costs decline as the number of hours per year of operation increase. Based on Figure XX, about 6,000 MW of generating capacity are needed to satisfy loads that occur 100 hours or less per year. A generator running for only 100 hours per year would cost $677/MWh ($0.68/kWh) for duct burners and $1,179 ($1.18/kWh) for simple cycle combustion turbines (about one tenth the cost of running 10 hours per year).~~

~~These figures mean that the avoided cost (or value) of an incremental MWh of load reduction declines as we achieve more of it. If demand response allows us to avoid serving the highest 10 hours of load, we save at least[5] $6,489 to $11,442 per incremental MWh, depending on the generator technology. But if the power system is able to achieve enough demand response to avoid serving the highest 100 hours of load, the minimum avoided cost drops to the $677 to $1,179/MWh range.~~

~~Approach 1 neglects a number of significant features of the Pacific Northwest's power system: There is a large component of hydroelectric generation in the region's power system, which can generally meet peak loads more cheaply than a thermal system. Further, there are large~~

[5] Most of this load is served even fewer than 10 hours per year and therefore has an avoided cost that is even higher.

~~transmission links with California and the Southwest, which facilitate sharing of generators, including peakers, with other regions and should generally reduce the cost of meeting peak loads. The Western power system includes a number of older, less efficient power plants that could be displaced by new peaking generators, with the operating cost savings offsetting part of the investment in the new units. The region also faces significant variation in the energy supplied by the hydroelectric system from one year to another, which changes the economics of thermal peaking generators (in poor water years the new peakers may run many more hours than usual).~~

~~Approach 2. To reflect these features more realistically, the second estimation approach used AURORA©, an electric price forecasting model, to simulate the West Coast electricity system. This model takes account of interaction between hydro and thermal generators, trade among the various regions, and the operational interaction among plants of different generating efficiencies. The cost of a power system built to provide a given level of service was compared to the cost of a power system that could avoid serving about 5 percent of its load during the most expensive hours (about 250 hours in an average year). The difference is the avoided cost of service in those hours, or the value of demand response in those hours. Our estimate of avoided cost using this approach is $1,029/MWh in an average water year. In drier-than-average water years the marginal generators would run more hours, reducing the cost/MWh of their production. Critical water conditions resulted in an estimated avoided cost of $519/MWh. In wetter than average years they would run fewer hours, resulting in a higher cost/MWh.~~

~~Both approaches lead to estimates of avoided costs that are several times the average rates paid by retail customers for electricity, and well above the incentives offered by regional utilities in their demand response programs in 2000-2001.~~

Potential size of resource

Since short-term demand response affects customers differently than does long-term demand response, it is to be expected that different amounts of each will be available. Some of the limited historical experience with short-term demand response has been translated into a range of short-term price elasticities.[6] By using elasticities from the lower end of that range, modest avoided costs, and modest peak loads,[7] it was estimated that short-term demand response of at least 1,800 megawatts could be developed in the Pacific Northwest.

Any estimate of longer-term demand response must be based on the region's recent experience using demand response to respond to the tight supply and high prices that persisted for weeks and months in 2000-2001. In that case, load reductions varied from month to month but totaled over 2,000 megawatts for significant periods. Many of these reductions came from the aluminum industry, which has unique characteristics that made it particularly attractive to reduce loads in the economic environment of 2000-2001. Similar reductions could be difficult or impossible to repeat if, as seems possible, the aluminum industry's presence in the region does not recover in the future. However, other economic activities, particularly those for which electricity is a significant part of the cost of production, may be candidates for long-term or at least seasonal demand response.

[6] Price elasticity is a measure of the response of demand to price changes -- the ratio of percentage change in demand to the percentage change in price. A price elasticity of –0.1 means that a 10% percent increase in price will cause a 1 percent decrease in demand.
[7] Our estimation process is described in more detail in Appendix X.

These very rough estimates of potential could be refined, although the basic conclusion to be drawn seems clear – even if they are wrong by a factor of two or three, the potential is significant.

Experience

Programs to stimulate demand response are gaining experience, in our region and nationally. In our region, a number of utilities have run short-term buyback programs; Bonneville, PGE and Pacific Power have the most experience in this area. Longer-term buyback programs were run in 2000-2001 by these utilities and others, including Avista, Chelan County PUD, Grant County PUD, Idaho Power and Springfield PUD. While this region has no significant experience with real-time prices, several utilities, including Tacoma Power, Puget Sound Energy and Montana Power (now Northwestern Energy) have offered service to customers at prices that followed the wholesale market on a daily or monthly basis. Puget Sound Energy, Portland General Electric and Pacific Power and Light have experience with pilot programs in time-of-day pricing. Milton-Freewater Light and Power has a program that allows the utility to control residential water heaters directly, and Puget Sound Energy ran a pilot program in which it directly controlled thermostats of residential heating systems. More detailed information about this experience is presented in the Appendix X.

Nationally, the best-known real-time price programs are at Duke Power, Georgia Power and Niagara Mohawk. Gulf Power has a voluntary residential time-of-day price program that incorporates a critical peak price for no more than 1 percent of all hours. Finally, there are a number of short-term buyback programs, run by utilities or independent system operators; some of the best-known are those run by PJM Interconnection, ISO New England, New York ISO and by several utilities and agencies in California.

The following will be incorporated in the Analysis, Conclusions and Recommendations Section for Demand Response

~~*Next Steps*~~

~~To realize the potential savings of demand response, the region needs to take a number of steps in the next few years:~~

~~*Fully Incorporate Demand Response into Utilities' Integrated Resource Plans*~~

~~As mentioned earlier, the greatest part of the potential benefit of demand response is due not to the avoidance of operating peaking generators, but to the avoidance of building them. After a generator is built, demand response allows the system to avoid only the operating cost of the generator. Before the generator is built, demand response can avoid not only the operating cost, but the construction cost as well. Depending on the hours of operation of the new unit, the total avoided cost of construction and operation may be five to 20 times the avoided cost of operation alone.~~

~~To take full advantage of the potential savings from demand response, planners need to take it into account from the beginning of their planning process, before they've committed to building new peakers.~~

~~*Refine Estimates of the Size of the Resource*~~

~~In order to fully incorporate demand response into resource plans, planners must have an estimate, in which they have confidence, of the size of the resource. As mentioned earlier, estimation of the size of the demand response resource faces the same problems as sizing the conservation resource, and more. Nevertheless it is necessary if planners are ever to rely on a significant amount of demand response instead of building new generation. This requires that load serving entities develop inventories of demand response capability, both long-term and short term, in their service territories.~~

~~*Preserve and Expand Options*~~

~~The need for demand response may have seemed to decline since the spring and summer of 2001, but if the events of the last few years have taught any lessons, one should be that conditions can change, and quickly. Maintaining and expanding the responsiveness of the region's demand to changing conditions is a cheap and attractive complement to building new generation capacity. Utilities should be able to offer programs to more participants. Participants should be able to identify more actions that will reduce load, given adequate incentive. We have a chance to build on recent experience and be able to respond quickly the next time conditions warrant.~~

~~*Refine Buyback Programs to Reduce Transaction Costs*~~

~~Much of the demand response enlisted in the 2000-2001 experience was the result of one-to-one negotiation, which was effective but relatively costly on a per-transaction basis. Utilities should be able to streamline some or all of these transactions (e.g. establishing many contract terms in advance, converting some negotiated deals to offers such as the Demand Exchange, etc.). Simplifying transactions will reduce the cost of making deals for both utilities and customers, which will make more deals and more load response possible.~~

~~*Resolve Regulatory Issues*~~

~~Cost-effectiveness: So that utilities can pursue demand response with confidence that regulators will allow them to recover costs, a clear standard of cost-effectiveness for the resource is needed. Avoided cost is the appropriate conceptual basis for cost-effectiveness, but since avoided costs vary with circumstances, no single value is appropriate for all utilities and all times. The estimates of avoided cost described earlier are reasonable starting points, but further work is needed before the avoided costs of utilities in the region are fully understood.~~

~~Retail access: Giving customers the ability to choose their electricity suppliers might have the effect of reducing access to demand response. Assume, for example, that Supplier 1 serves industrial customers, whose loads are mostly constant, while Supplier 2 serves residential and commercial customers, whose loads exhibit daily and seasonal peaks. Supplier 1 needs little peaking generation to serve its load, while Supplier 2 needs significant peaking resources.~~

~~There is a potential regional benefit in Supplier 2 being able to obtain voluntary load reductions (demand response) not only from its own customers, but from Supplier 1's customers as well. Such transactions are likely to involve all three parties (i.e. the customer and both suppliers), and could need explicit approval from regulators. It would be unfortunate if suppliers, regulators and~~

~~customers can't overcome any extra complexity to complete transactions that are in the regional interest.~~

~~*Explore Ways to Make Price Mechanisms More Acceptable*~~

~~Some of the advantages of price mechanisms over the alternative means of stimulating demand response were discussed earlier. Price mechanisms avoid transaction costs. They can reach more customers. They provide appropriate incentives when prices are low as well as when they are high. They can provide appropriate incentives for every hour of the year.~~

~~However, there are significant obstacles that hinder the adoption of price mechanisms. These obstacles may prove to be intractable, at least for now, but serious efforts are needed to identify ways to make price mechanisms more practical and acceptable. Such options as two-part real-time prices and time-of-use prices with critical peak prices deserve close examination and testing.~~

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Risk Assessment & Management

Background and Issues

The Western Electricity Crisis of 2000-2001 was a potent reminder that the electricity system is inherently risky. The crisis posed many important questions for the Fifth Power Plan:

- How much generation is enough, and how can we be assured it will be developed?
- What is the value of demand response?
- What is the value of sustained investment in conservation?
- What is the value of resource diversity? How should uncertainty about fuel and wholesale power prices affect our decisions about resource additions?
- How does transmission improve system reliability?
- What is the possible impact of global climate change on our power plan?

The evaluation of each of these issues is dependant on our view of risk and uncertainty. For example, we expect that demand response could be available in large quantity, but only if incentives exceed around $100-150 per MWh. Even though demand response programs are relatively inexpensive to maintain, most forecasts of wholesale electric power prices rarely, if ever, exceed this value. Our experience with the energy crisis of 2000-2001, however, has shown that unforeseen circumstances can send prices higher than this for extended periods. Consequently, key issues in this power plan require an analytical approach that addresses such rare but extreme events.

Risk assessment and management have always been important elements of the power plan. In prior plans, power plant forced outage rates, load uncertainty, and hydro generation variability figured prominently in the conclusions of the plan. Gas and coal price excursions were incorporated in forecasts and directly in sensitivity analyses. The capability to export and import various amounts of power to and from outside the region were also considered. Since the first power plan, the Council has analyzed the value of shorter lead times and rapid implementation of conservation and renewables as well as the concept of "optioning" generating resources – carrying out pre-construction activities and then, if necessary, delaying construction until conditions favor going ahead.

In this plan, we further integrate risk assessment and management into our analysis and extend our assessment of risks to such issues as market price uncertainty, aluminum price uncertainty and emission control cost uncertainty. We include periods up to several years during which power and fuel prices, as well as other sources of uncertainty, deviate significantly from equilibrium levels. We abandon the assumption of perfect foresight in our planning to better assess the value of risk mitigation.

Definitions

Definitions of the terms used to address risk assessment and management are presented below.

- **Uncertainty** is a measurement of the quality of our information about an event or outcome. Some future events are uncertain, but there is a significant amount of information about their likelihood, and it is unlikely additional information would reduce their uncertainty. For example, we don't know what the total annual flow at Bonneville Dam will be in 2010, but based on 61 years of historical records, we are comfortable estimating the distribution of different outcomes. Other future events are more uncertain, like prices of natural gas and electricity. We have some theory and experience to inform us but have also seen our expectations confounded. For others, we have very little to go on. For example, we don't know whether a carbon tax will be in place in 2010, and we have almost no objective basis for attaching likelihood to the implementation of the tax or its magnitude. Future events therefore lie along a spectrum of varying degrees of uncertainty.

- **Futures** comprise events or circumstances we cannot control. Futures are combinations of particular samples of each source of uncertainty, usually specified over the entire 20-year study. For example, a future would include paths for loads, natural gas prices, water conditions, electricity market prices and so on over the 20-year planning period. Whether these sources of uncertainty produce risk or not depends on the plan we adopt.

- **Plans** are future actions that we can control. Plans include the construction of new power plants and the implementation of demand-side strategies or mechanisms. Different resources also provide differing amounts of planning and operating flexibility. These are inherent attributes of each plan.

- A **Scenario** consists of a plan considered under a specific future. When we want to know the outcome for a plan, such as a specific schedule of power plants under a particular set of assumptions for gas price, energy requirements, and so forth, we consider that scenario.

- **Risk** is a measure of bad outcomes associated with a given plan. Our primary outcome is the net present value total system cost for a 20-year scenario. A bad outcome arises when a plan results in high development or use costs under a specific future. Risk is a measurement of the bad outcomes from the distribution of *all* outcomes associated with the plan under *all* the futures.

  The Council has adopted a quantitative measure of risk. It captures both the likelihood and magnitude of bad outcomes. An unlikely outcome may still present significant risk if its effects are catastrophic.

- A **Risk Mitigation Action** is a plan or some element of a plan that reduces our risk measure. In our example, the power plant may protect us from load risk when requirements fall, because we can turn off generation and save fuel cost. A demand-side strategy can protect us from fuel price risk.

Uncertainties

What are some of the primary sources of uncertainty in our future, and who bears the associated risks? What is the likelihood of particular futures and how do the various sources of risk conspire to produce particularly harsh futures?

We have attempted to address the following sources of risk in our analysis:

- Wholesale power prices – Many electric power price forecasts are based on long-term equilibrium models. While useful to understanding price trends, these models ignore the disequilibrium between supply and demand that is commonplace for electricity. Disequilibrium results from less than perfect foresight about supply and demand, from inactivity due to prior surplus and from overreaction to prior shortages. Periods of disequilibrium can last as long as it takes for new capacity to be constructed or released, or surplus capacity to be retired or "grown into". Resulting excursions from equilibrium prices can be large and are a significant source of uncertainty to electric power market participants.

  To capture these effects, some of the most detailed and complex modeling is reflected in our simulation of wholesale electricity prices. Electricity prices are related statistically to hydropower availability, loads and natural gas prices. In addition, market prices for electricity are adjusted to reflect changes in available generation relative to load. For a given load, additional generation tends to drive down electric power prices. In particular, if generation would initially exceed requirements plus the region's ability to export, prices would be reduced until generation equaled loads plus export capability. Similarly, if generation were inadequate to meet requirements given the region's import capability, prices would be increased until the situation was resolved, e.g., loads were reduced or additional resources came into service.

- Plant Availability - Power plants are not perfectly reliable, and forced outages are an important source of uncertainty. The analysis includes simulation of forced outages based on typical forced outage rates for the generating technologies considered.

- Load Uncertainty - The Council's load forecast for non-aluminum loads serves as a basis for our expected load and load probability distribution. A range of load growth paths corresponding to the Council's demand forecast range are modeled, including some excursions of two to four years for business cycles.

- Aluminum Load Uncertainty – Aluminum smelters in the Pacific Northwest have represented a substantial portion of regional loads in the past. This introduces a source of uncertainty directly related to the relative price of aluminum and the price of wholesale power. When electric power is costly relative to aluminum prices, smelters will shut down. We explicitly model aluminum prices to capture this uncertainty. Modeling other commodity prices is also possible but has not been done for these studies.

- Fuel Prices - Price paths for natural gas and coal are modeled as an uncertainty. The basis for the natural gas price forecast is the Council's most recent forecast including estimates of uncertainty in the expected annual price. Brief excursions from the path are modeled which may last from six months to four years, and we model price recovery as well. The duration of the excursion and the duration of the price recovery are both functions of the size of the excursion. The primary source of coal price uncertainty is that associated with a CO_2 emissions tax.

- Hydro-generation - For each hydro year in the study, streamflows and generation are drawn from a 50-year history of data. The hydro-generation reflects constraints associated with the 2000 biological opinion.

- Climate Change - In our analysis we consider the possible impact of policy responses to global climate change. The Council is not taking a position on the likelihood of climate change, much less the timing and magnitude of possible policies adopted to mitigate global climate change. It recognizes the uncertainty regarding that outcome and its risks, including the potential for increasing temperatures on snow pack, stream flow and hydro-generation and the risks that possible policy responses pose for different resource choices. In this analysis, the potential for a carbon tax is modeled by a random step increase in carbon tax of up to a maximum of $30 a ton in every year after an election year between now and 2020.

  The carbon tax is intended to reflect costs to mitigate greenhouse gas emissions. It is a surrogate for any number of measures, including an emission trading credit program and the cost of greenhouse gas emission control equipment.

- Other Emission Costs - Power plant costs all include the best available technology emission control equipment costs. We do not model fuel-specific emission risk, such as mercury sequestration for coal or particulate emission for diesel-fired power plants.

- Continuation of production tax credits, green tag value, and integration costs - Wind generation has been looking more attractive from an economic standpoint over the last several years, in part because of tax credits and favorable forecasts for green tag values. As wind becomes established as a source of energy, some parties feel that incentives and other support for wind may give way to market forces. We reflect this uncertainty in our modeling

- Distribution Uncertainties and Modeling Errors - An important source of concern to decision makers is the validity of a computer model's representation, the accuracy and completeness of input data, and the potential that a user may simply make a mistake in applying the model.

One of the mechanisms for dealing with this sort of risk is a careful evaluation of whatever plan is produced by the computer model. Regardless of the nature of the uncertainties and the probabilities associated with futures, the resulting plan must make sense to the decision-maker, and the means of risk mitigation must be clear and compelling. The Council staff uses models to screen plans, not as a substitute for experience and judgment.

Another check on our work is sensitivity analysis around the distributions for the uncertainties. Although "uncertainty about uncertainty" does not make sense for a single decision-maker, there will be a diversity of opinion among decision makers about the uncertainty of specific forecasts. The resource plan produced by Council staff incorporates distributions of forecasts prepared or reviewed by experts in an open forum. Nevertheless, it may be useful to an individual who believes he or she knows better, or is more dubious than these experts, to see the effect their greater or lesser uncertainty would have had on the selected plan.

There are other sources of uncertainty, including changes in technology and policy, fish and wildlife programs and the transmission system, which have not been treated explicitly. These sources of uncertainty and any treatment in this analysis are described in the appendix.

The Council staff contracted with BHM3 Consultants to perform detailed statistical analysis on the relationships between hydro-generation, loads, temperature, natural gas prices, electric power prices and transmission. The System Analysis Advisory Committee reviewed the result of these analyses. These analyses form the basis for our representations of price paths, uncertainties, volatilities and correlations. These results of these analyses are included in the appendix.

Objectives and Measures of Risk

How do we determine the costs and benefits of our various plans, how do we measure risk, and whose assessment of risk should we use?

We call our approach to resource planning "risk-constrained least-cost planning." Given any level of risk tolerance, there should be a least-cost way to achieve that level of risk protection. The purpose of our studies is to define those plans that do just that.

Given a particular future, our primary measure of a plan is its net-present value total system costs. These costs include all variable costs, such as those for fuel, variable operations and maintenance (O&M), certain short-term purchases, and future fixed costs associated with capital investment and operation and maintenance. The present value calculation discounts future costs to constant 2004 dollars using a real discount rate of four percent.[1] This treats current and future costs on a comparable basis. Total net-present value costs are demonstrably a better measure of economic value than internal rate of return, retail power rates, or benefit-cost ratio.

[1] See appendix ??.

Environmental impacts are incorporated by monetizing whatever measures would need to be taken to neutralize those impacts.

If the future were certain, net present value total system cost would be the only measure of a plan's performance we would need. But since the future is uncertain, we need to evaluate plans over a large number of possible futures. To evaluate a plan completely, we would, in principle, need to examine the entire distribution of possible outcomes associated with the various futures we are examining. For our analysis, the typical evaluation of a plan considers 750-1000 futures. The performance of a plan under most futures is estimated by the *expected* net present value total system cost – the frequency-weighted average net present value total system cost (average cost) evaluated over all the futures. This is illustrated in Figure 1 below. Each box represents the net present value cost (sorted into "bins" – a narrow range of net present value total system costs) for a scenario, i.e., for the plan under one particular future.

But the expected net present value cost does not give us a picture of the risk associated with the plan. There are a number of possible risk measures that could be used. A summary measure of risk called "TailVar90" was chosen. This choice of risk measure and its comparison with other risk measures that we considered appears in the appendix. Very briefly, TailVaR90 is the average value for the worst 10 percent of outcomes. It belongs to the class of "coherent" risk measures that possess mathematical properties that are superior to alternative risk measures. Since 1998, when papers on coherent measures first appeared, the actuarial and insurance industries have moved to adopt these, abandoning non-coherent measures such as standard deviation and Value at Risk (VaR). Thus performance of each plan over all the futures is summarized by the expected net present value total system cost and the risk measure, TailVar90.

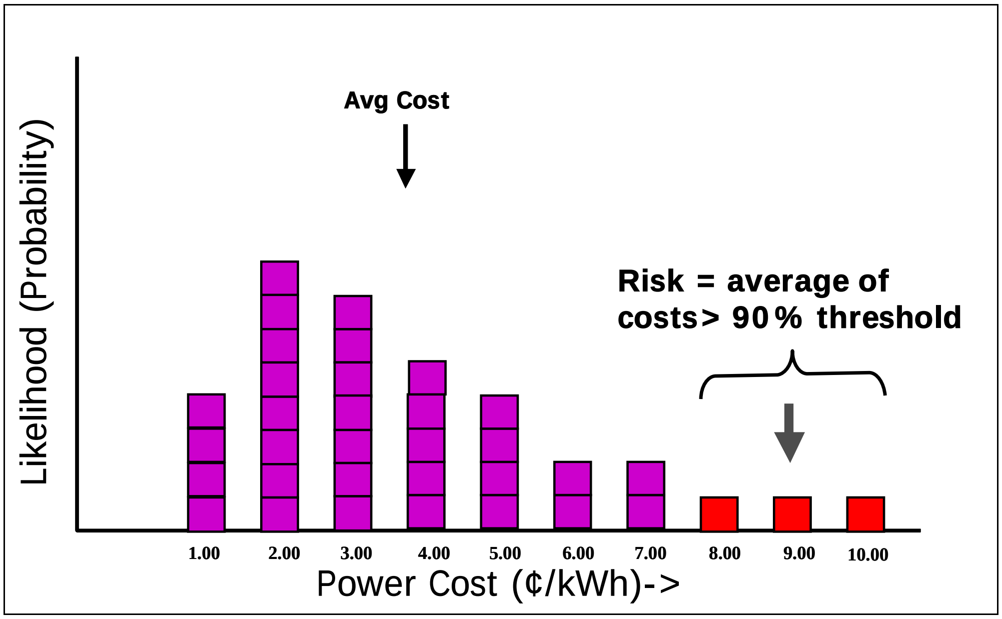

Figure 1: Plan Costs over all futures

Assessing Plan Performance and Identifying Optimal Plans

We use three computer models to arrive at the recommended plans, plans that are least-cost for a given level of risk. The first is Olivia, a model that creates an Excel ® workbook portfolio model. We will not say much more about Olivia here, because once a workbook model has been created for a system, such as the regional power system, we do not use Olivia again. Instead, we make minor refinements directly to the workbook model. Olivia provides a tool for others to perform their own risk analysis using concepts and techniques developed by the Council staff.

The second model is the Excel® workbook model itself, which we refer to as "the portfolio model." This workbook model is the calculation engine. It estimates costs of generation, purchases or sales of wholesale power, and capacity expansion over the 20-year study time period. We use an Excel add-in to run a Monte Carlo simulation of the scenarios, with each game corresponding to a future[2]. This simulation gives rise to the cost distribution illustrated in Figure 1 for each plan.

In Figure 2, we illustrate the kind of calculation that is being made by the portfolio model in each future. This example shows energy use resulting from a plan over a two-year time period for the fixed future. Our future defines hydro generation, loads, gas prices, and so forth in each hour. Given these circumstances, existing and future resources in the plan generate power, largely in response to wholesale electricity prices. Because our generation rarely exactly matches our load, we buy power from the wholesale market or sell into the wholesale market. We add up all the costs and revenues in each hour, add any future fixed costs for existing and new generation or capital costs for new generation and conservation, and discount the dollars to some fixed point in time. Of course, in our portfolio model we do this for 20 years, not for two years, but the process is identical.

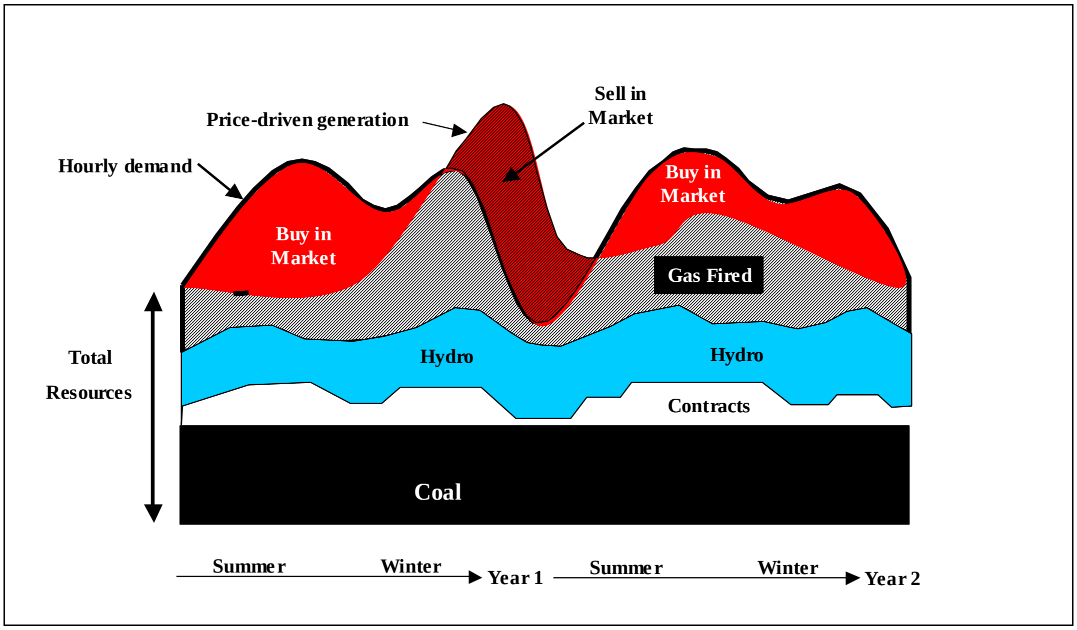

Figure 2: Calculating Cost for a Scenario

[2] Decisioneering's Crystal Ball®.Olivia produces a workbook that is compatible with Crystal Ball.

We typically examine 750-1,000 futures for each plan and about a 1,000 plans per study so we are looking at around a million scenarios. If we were to perform hourly calculations for each of these 20-year scenarios, computation time would be prohibitive.[3] For this reason, we have developed algorithms to estimate plant capacity factors, generation, and costs for periods of one to several months. Using these techniques, we represent the 20-year study period by 80 hydro-year quarters on peak and another 80 off peak. Since the model does not break the Northwest into sub-regions, we do not model cross-Cascade and other intra-regional transmission constraints, but we constrain imports and exports to 4,000 megawatt-quarters, before any contracts.[4] Transmission constraints are considered outside the model. We have also aggregated existing regional thermal resources down to about 30 plants with similar characteristics. Hydro generation is based on draws from a 50-year streamflow record and system constraints determined by the 2000 Biological Opinion (BiOp). Operation of the region's seven remaining smelters is determined by the relative price of aluminum and wholesale electricity.

The third model we use helps us to find the least-cost plan for a given level of risk. This model is actually another Excel add-in.[5] This add-in uses a variety of techniques to find the least-cost plan for a given level of risk as efficiently as possible. The process of selecting a risk constrained least cost plan is illustrated with the following diagram:

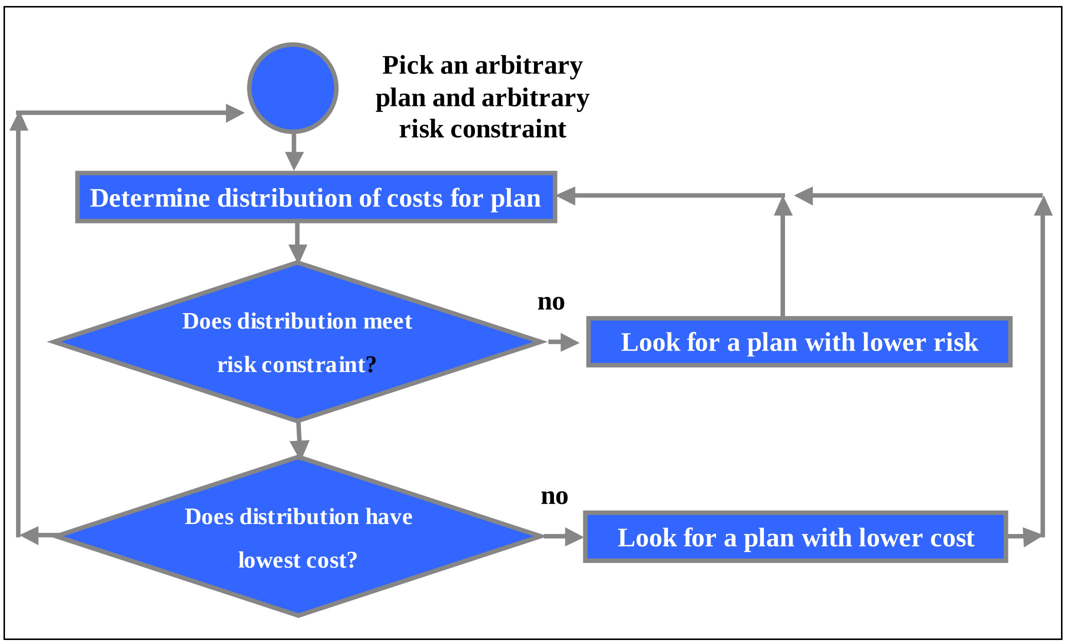

Figure 3: Finding the Risk-Constrained Least-Cost Plan

The program first seeks a plan that satisfies a risk constraint level. Once it has found such a plan, the program then switches mode and seeks plans with the same risk but lower cost. The process ends when we have found a least-cost plan for each level of risk.

[3] One estimate using AURORA® run times put the study at a little over 85 years.
[4] Contracts may be fully counter-scheduled.
[5] Decisioneering's OptQuest®.

The necessity of using the approach to find the least-cost plans becomes evident when one attempts to estimate the number of potential plans that may exist. We typically constrain cumulative capacity expansion for four or five resource candidates to half a dozen levels at each of eight points in time.[6] Even with this modest choice, the number of potential plans is billions of billions.

If we plot the outcome for each plan as a point with coordinates corresponding to the expected cost and risk of the plan, we obtain a new distribution as illustrated in Figure 4. Each point on the figure represents the average cost and TailVar90 value for a particular plan over all 750 futures. The least-cost outcome for each level of risk falls on the left edge of the distribution in the figure. The combination of all such least-cost outcomes is called the "efficient frontier." Each outcome on the efficient frontier is preferable to the outcomes to the right of it, since it has the same risk as those outcomes, but lower cost. Choosing from among the outcomes on the efficient frontier, however, requires accepting more risk in exchange for lower cost, or vice versa. The "best" outcome on the efficient frontier depends on the risk that can be accepted. This topic is described in greater detail in the appendix.

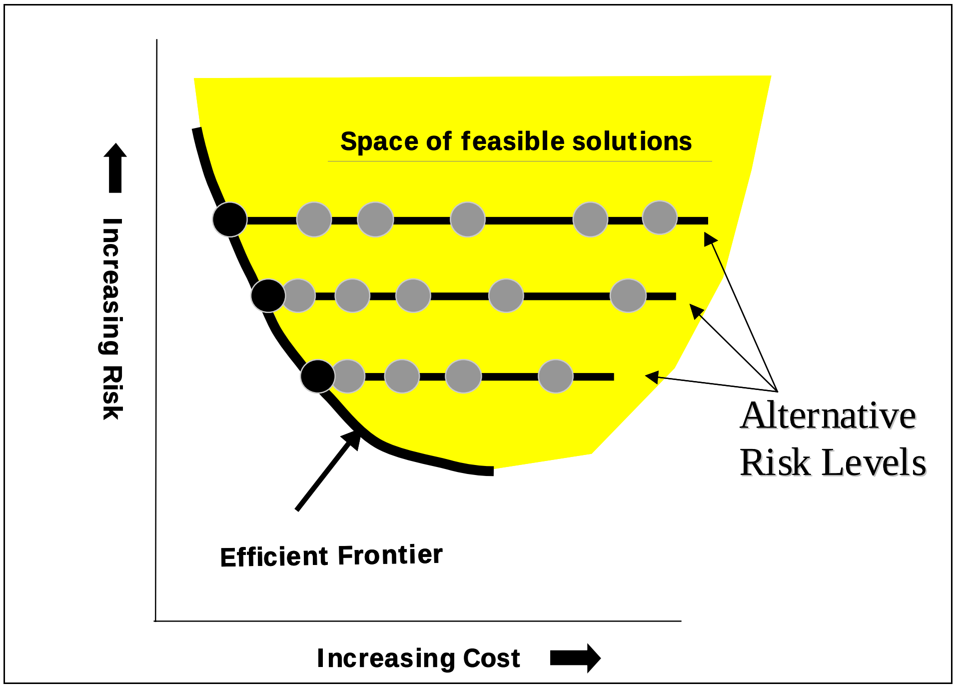

Figure 4: Feasibility Space

The choice of risk tolerance has been discussed with the Council and with the System Analysis Advisory Committee. A single choice cannot represent every decision-maker in the region. Arguably, it may be meaningless to attempt to arrive at such a risk/cost trade-off for the region. While it may not be possible to settle on a level of risk tolerance that represents all parties in the

[6] The exact choice of the points in time differ from study to study, but typically we concentrate more of these points around periods we are most interested in, like the near-term action plan horizon or when a lot of resource expansion is taking place.

region, there are important lessons to be learned from consideration of the issue. Risks and risk mitigation measures identified for the region are likely to be at least roughly representative of many parties in the Pacific Northwest power industry. This description of analysis and methods should spur consideration of risk by those decision-makers in the region who are in a position to implement risk mitigation.

Moreover, the analysis presented in the Plan identifies a value for risk mitigation resources and programs to the region. Focusing exclusively on the least-cost plans without consideration of risk could expose the region to significant risk. The analysis has estimated the increase in expected cost that must be paid in order to secure a given increase in risk protection cost-effectively.

Other participants will no doubt have their own measures of risk and cost, but the process of estimating the insurance premium illustrated here should encourage load-serving entities and their representatives to re-examine their assumptions regarding least-cost planning and the role risk plays. It may provide a better understanding of the value of risk mitigation to the region as a whole. We expect that individual participants, by insuring themselves against the risks that they face will help to secure a more reliable system for the region. The tools and methods that we have developed to perform this analysis are available to decision-makers in the region.

Risk Mitigation Actions

How can we reduce risk and what is the right amount of risk reduction? What level of risk mitigation does the region require? How do various resources contribute to risk mitigation? Who pays for risk mitigation?

The value of risk management resources is the contribution they make when our foresight is not perfect. Their value derives from their ability to respond under abnormal circumstances of price, loads, resource availability, and so forth. Moreover, their value is directly related to the probability of these events.

Risk mitigation can be thought of as resulting from two types of actions:

- Hedging - A commitment to a plan that symmetrically reduces uncertainty; and
- Flexibility or optionality -- the right, but not the obligation, to take a particular action

Hedging

Roughly speaking, hedging is placing a bet that offsets a bet already on the table. If our original bet is wrong, the hedge reduces the amount that we lose. Conversely, if our original bet is right, the hedge reduces our winnings. In the specific context of power planning, a utility may want to add wind generation to its resource portfolio if the portfolio contains a lot of combustion turbine generation and the utility is concerned about risks due to natural gas price increases. If natural gas prices go up, the utility’s costs do not go up as much on average as they would if it had not invested in wind generation. If natural gas prices decrease, however, some of the reduction in natural gas costs is offset by the utility’s commitment to the fixed costs of a wind power plant.

By this definition, the effect of hedging is always symmetrical, mitigating the worst outcome, but moderating the best outcome as well.

Flexibility or optionality

In contrast with hedging, there are risk measures that provide "optionality" or "flexibility," and are asymmetrical in their effect. One of the most familiar examples is insurance. If we think of our home or our car as an investment, insurance protects us from futures or situations that diminish or wipe out the value of our investment. The insurance premium offsets a part of the value of the investment in all futures, but we are shielded from loss in bad futures.

There are a host of examples of options in the power industry. The Council's plan deals primarily with physical processes or decision-making flexibility. Because of the strong association with financial options and the confusion that that association may create in the reader's mind, the term "flexibility" will be used when referring to physical process or decision-making flexibility.

Examples of flexibility are plentiful. A combustion turbine, for example, represents the flexibility to exchange natural gas for electric power. When electricity is expensive relative to natural gas, the turbine's owner tends to generate electricity from the gas and sell that. If natural gas is expensive relative to electricity, the owner tends to refrain from generating and may either resell the valuable gas or hold it in storage. Demand response represents another form of this flexibility. When electricity is expensive relative to a commodity that a utility customer is producing, the load serving entity and its customer may agree to sell the more expensive electricity and compensate the customer with more money than the customer would have made producing the commodity. These are examples of short-term flexibility.

Examples of long-term flexibility include a decision maker's ability to cost-effectively cancel or defer a project. The ability to add small increments of capacity, often referred to as "modularity," is another form of planning flexibility, as is the ability to construct a plant very rapidly to take advantage of current market conditions. Demand response, such as the response of aluminum smelters to wholesale price excursions, where it may take several months to efficiently shutdown or restart an industrial facility, is an example of long-term flexibility.

The value of planning flexibility was abundantly demonstrated during the energy crisis of 2000-2001. Few of the conventional power plants that entered construction during the crisis contributed to moderating the elevated prices that ensued because the episode was over before construction was completed. What contributed most to re-establishing supply-demand equilibrium, instead, was reduced irrigation, reduced industrial and aluminum smelter load; other demand response programs through which consumers reduced demand in response to financial inducements; reductions in spill that made additional hydro generation available; and diesel generators that could be brought online very quickly. These are examples of the value of planning flexibility.

The treatment of flexibility, and in particular long-term planning flexibility, distinguishes the Council's study and analytical technique from many of the techniques that are currently used to evaluate resource plans. This distinguishing feature is critical to our evaluation of risk

Planning flexibility allows a plan to accommodate changes from one future scenario to another. By automating this process and applying probabilities to the various futures, the Council's analysis can estimate the expected cost of accommodating the full range of scenarios. Plans containing resources with planning flexibility can manage this accommodation at a lower expected cost, other things equal.

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Transmission

Introduction

An electrical power system requires constant, second by second, balancing of supply, demand, and transmission capability. Transmission system operators are primarily responsible for maintaining this delicate balance. Transmission system operations are organized into "control areas," whose operators must continuously balance electricity demands with electricity generation while keeping power flows over individual transmission lines within specific limits for system operating reliability. There are 13 control areas in the Pacific Northwest. Some control areas, such as Bonneville and PacifiCorp (which has two) are quite large, and some, such as Grant County PUD, are relatively small. The failure to maintain control over the transmission system can result in failure of the entire electrical system as illustrated by the Midwest and Northeast blackout of August 14, 2003.

The transmission system is operated for two primary objectives: (1) the security or reliability of the physical system; and (2) the economy of the system. Thus, from an operational perspective, it is transmission system operators who are responsible for achieving an efficient, economical, and reliable power supply. The Council's interest in transmission stems from its charge under the 1980 Power Act to assure an adequate, efficient, economical and reliable power supply for the region. Nevertheless, in past power plans, the Council did not address transmission directly. Instead, the plans focused on long-term resource adequacy and cost effectiveness. It was assumed that the incentives to assure the reliable and economic operation of regulated, vertically integrated utility service areas were adequate and that incentives were sufficient to ensure transmission system expansion if needed.

These assumptions are no longer warranted. The reliability of the system, which was assumed to be under adequate control in previous plans, is now threatened. Further, it has become the case that longer-term resource adequacy and cost effectiveness no longer solely depend on Council and utility planning, but also, to a significant degree, on a well-functioning wholesale power market. The transmission system is integral to that market and is, therefore, an important focus for the Council. The region has suffered from the consequences of a poorly designed wholesale power market, and the Council does not want to see those experiences repeated.

Description of the Problems

Over the last 30 years, changes in the basic structure of the electricity industry have created challenges to the traditional operation of power systems. Changes in the technology of electricity generation have gradually led to more competition and a weakening of the rationale for monopoly electricity generation by vertically integrated utilities. New generating technologies such as combined cycle combustion turbines, cogeneration, wind power, and geothermal generation tended to be smaller in scale and lower in capital requirements than the then-dominant utility-owned coal and nuclear plants. The 1978 Public Utility Regulatory Policies Act (PURPA) created a class of non-utility generators that had the right to sell their electricity to regulated utilities at prices that utilities would have incurred to develop their own generation. Ultimately, as technology continued to improve and electricity generation by independent parties proved increasingly competitive, Congress and the Federal Energy Regulatory Commission began taking actions to further facilitate competition in wholesale power supply.

Today, independent generators play a significant role in electricity supply, and these entities have developed most of the recent and proposed new generating plants. While many independent generators were hurt financially in the aftermath of the 2000-2001 electricity crisis, it would be premature to think they will not be an important factor in the future. Electricity is, and will continue to be, bought and sold in wholesale markets in amounts and patterns not contemplated when the existing transmission systems and their operational procedures were put in place. This has created problems in the operation and control of the transmission system that, if not adequately addressed, threaten the reliability and economy of the region's electricity supply.

The growth of independent power generation and increased wholesale electricity trading have become increasingly incompatible with the traditional electricity system operation by individual control area operators, usually affiliated with regulated utilities and their affiliated merchant generators. Issues of how best to manage actual power flows for reliability and economy have become increasingly troublesome. Similarly, the problem of planning for and implementing transmission system expansion has become much more complex. The problem is no longer that of a single company linking its generation and loads. The issue now is how utilities, independent power developers, transmission owners, load-serving entities and even consumers can make coherent decisions about what to build and where to build in a vast interconnected and interdependent system, and the incentive and cost recovery questions raised by those decisions.

By now the problems facing the regional transmission system as a result of industry restructuring are pretty clearly understood by parties close to the issue. In May 2002 the Council issued a paper that described the problems and discussed possible solutions.[1] More recently the Regional Representatives Group (RRG) of Grid West developed a list of transmission problems and issues that reflects many of the same problems.[2] The problems include:

- Difficulty in managing unscheduled electricity flows over transmission lines leading to increased risks to electric system reliability;
- Lack of clear responsibility and incentives for planning and implementing transmission system expansion resulting in inadequate transmission capacity;
- Inability to effectively monitor the wholesale electricity market, identify market power abuse, or provide mitigation and accountability;
- Difficulty in reconciling actual physical available transmission capacity with that available on a contractual basis, resulting in inefficient utilization of existing transmission and generation capacity;

[1] http://www.nwcouncil.org/energy/transmission/rto2002_0517.pdf

[2] RTO West was renamed Grid West in March of 2004; The issues list may be found at http://www.rtowest.com/Doc/RRGA_ReformattedList_July292003.pdf

- Transaction and rate pancaking, i.e. contracting and paying for the fixed costs of multiple transmission segments on a volumetric basis to complete a power sale, resulting in inefficient utilization of generation; and
- Competitive advantage of control area operators over competing generation owners causing inefficient utilization of generation and a potential proliferation of control areas with greater operational complexity.

Attempting to Correct the Problems

The problems likely to be created by the restructuring of electricity markets have been recognized for some time. The 1996 Comprehensive Review of the Northwest Energy System concluded:

> Transmission is the highway system over which the products of electrical generation flow. If there is to be effective competition among generators, transmission facilities should be operated independently of generation ownership. An independent grid operator (IGO) regulated by the Federal Energy Regulatory Commission with broad membership, including Bonneville and the region's other major transmission owners, is proposed as a means of ensuring independence of transmission operation and improving the efficiency of transmission operation. An independent grid operator should also have clear incentives to maintain reliability and encourage efficient use of the transmission system.[3]

The Northwest has devoted enormous efforts to trying to find agreement on changes to the management and operation of the regional transmission system, first with IndeGO and later with RTO West. However, while there has been growing consensus on the problems, there has not been agreement on the solutions. Consequently, there has been little progress in implementing needed changes to the transmission system. Efforts by the Federal Energy Regulatory Commission to mandate specific solutions on a national level have not achieved substantial support in the Northwest, and have probably exacerbated the impasse.

For a number of reasons, this region should be at some advantage in adapting to the restructuring of electricity markets. To a greater extent than most areas, the Pacific Northwest has a long experience with active wholesale markets, and has a well-developed transmission system to facilitate them. This experience is due to the Bonneville Power Administration marketing wholesale electricity throughout the region, the location of much generation distant from loads due to the locations of federal dams and coal deposits, and active seasonal exchanges and non-firm power sales to California. At the same time, these factors have created resistance to the dramatic changes to transmission management proposed by FERC, with many in the region feeling that such large changes are not appropriate for the Pacific Northwest.

Recently, the Regional Representatives Group (RRG) of Grid West has taken some promising steps toward a resolution. The RRG, composed of members of interest groups in the region, including Bonneville, other utilities, and regulators, has worked collaboratively to identify a

[3] Comprehensive Review of the Northwest Energy System: Final Report. (96-CR26). December 12, 1996. page 8. http://www.nwcouncil.org/library/1996/cr96-26.htm

structured, incremental approach to reforming the management and operation of the transmission system. The proposal identifies a desirable target state, but relies on incremental and voluntary steps toward that state. A structured process is defined for agreeing on significant changes to the system over time. Many details remain to be ironed out, but the process has potentially moved the region beyond its impasse and begun a constructive process to resolve the most serious problems. The Council supports this effort. It is important that the region move ahead to correct the growing problems in the regional power system.

Characteristics of a Well-Functioning System

There are four characteristics of any successful transmission operation and management solution. In addition, there are a number of considerations that must be addressed in implementing changes with broad regional support.

Reliability

The foremost characteristic is that reliable operation of the regional power system be established and maintained. Central to this characteristic is a better set of tools for the region's Reliability Coordinator, and movement toward transmission system management based on power system flows rather than contract paths. Consolidation of control areas will help this process work better. Any entity that operates a consolidated transmission system needs to be independent of commercial conflict of interest, but also accountable to the region.

Efficiency

A second key characteristic is to provide efficient, low-cost transmission system operation and to facilitate the operation of a well-functioning electricity-trading platform. This requires a system for transmission congestion management that promotes least cost solutions whether they be from generation redispatch, transmission system upgrades, or demand-side alternatives. Success in this area will require wholesale electricity markets and transmission systems that are open and accessible to all participants on an equal, nondiscriminatory basis. Transmission users need to have easy access to information about available transmission capacity and other market conditions so that all economic transactions can be executed.

Planning and Capacity Expansion

Part of electricity restructuring was the administrative separation of electricity transmission from generation. The separation was intended to improve access to the transmission grid for non-transmission owners, but it also had the effect of undermining an integrated planning process for both added generation and development of new transmission capacity. To ensure reliability and efficiency in a restructured environment, policy planners need to support a regional, or West-wide forum or organization with responsibility for a forward-looking assessment of long-term transmission system requirements and a mechanism to encourage investments to meet those requirements. This planning needs to consider future capacity needs in transmission, generation, and demand management and their possible locations; who will make investments in future capacity; how the costs of capacity expansion will be recovered; and how adaptable the system will be to future changes in loads or technology.

While lead times for the development of new generation have become shorter, the lead-time for major transmission improvements can be a major barrier to acquisition of needed and cost-effective resources. [Potential insert here for the results of Jeff's transmission analysis]

Efforts are under way, both westwide and in the Pacific Northwest, to assess the long-term transmission system capacity expansion needs. The Seams Steering Group – Western Interconnection (SSG-WI) Planning Work Group provides a forum for an expansive westwide look at potential transmission needs over the next 10 years. It is intended to complement existing WECC reliability and path rating work. The Northwest Power Pool's Transmission Planning Committee formed an open-membership group called the Northwest Transmission Assessment Committee (NTAC). The NTAC "is an open forum to address future planning and development for a robust and cost-effective NWPP area transmission system."[4] The NTAC is developing its study program and has begun some initial focused studies.

Bonneville convened a large group of stakeholders beginning in January 2003 to consider how to identify and implement alternatives to transmission construction. These alternatives include demand reduction programs, conservation, distributed generation, and other possible approaches. Working with Bonneville's transmission business line, this group is working on screening criteria, pilot projects, funding issues, and institutional hurdles. The product of this effort should provide an improved approach to incorporating alternatives into the transmission planning process.

Market Monitoring and Evaluation

Active market monitoring is important to making the current hybrid regulated/deregulated energy market work successfully. The transitional nature of these markets has resulted in vulnerability to poor market designs, misplaced incentive structures, and exploitation of the markets in unintended ways. The nature of electricity markets, at least for the foreseeable future, will likely result in cases of significant market power under tight market conditions. An independent transmission operator should collect the data necessary to evaluate the market's performance and report regularly on its competitiveness and efficiency.

Other Considerations: Fairness and Protection During the Transition

As the region struggles toward solutions to transmission system problems, there are important concerns and policies that need to be considered to maintain fairness and achieve regional support for needed changes in power system operations.

- To the extent possible, neither the costs of transmission nor the quality of service should be shifted among current transmission system users.
- Existing transmission rights should be preserved.
- The ability of utilities to serve their native loads should not be impaired.
- Electricity markets and transmission system operations should not impair the benefits from coordinated operation of the Columbia River Power System.

[4] http://www.nwpp.org/ntac/

- To the extent possible, implementation of changes to the management and operation of the power system should be phased in and maximize the utilization of existing organizations and equipment to minimize additional costs.

Conclusion

It is important that the region address the current problems in the management and operation of the regional transmission system. The problems are now widely understood. The Council is pleased that the RRG process appears to have moved beyond regional conflicts over transmission reform. It is making progress, through a collaborative process, in resolving the more serious problems affecting the transmission system. The Council supports the RRG process and will monitor its progress toward a transmission system that achieves the characteristics of a well-functioning power system, while fairly preserving important regional values. The Council will continue to make its staff available to participate in the RRG process.

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Power Planning and Fish and Wildlife Program Development

Background

The Columbia River Basin hydroelectric system is a limited resource that is unable to completely satisfy the demands of all users under all circumstances. Conflicts often arise that require policy decisions to allocate portions of this resource as equitably as possible. In particular, measures developed to aid fish and wildlife survival often diminish the generating capability of the hydroelectric system. Conversely, "optimizing[1]" the operation of the system to enhance power production has detrimental effects on fish survival.

The Council has dual responsibilities to "protect, mitigate and enhance" fish and wildlife populations (affected by the hydroelectric system) while assuring the region "an adequate, efficient, economical and reliable" power supply. Although developed at different times and under different processes, the Council has attempted to use an integrated approach in developing both its fish and wildlife program (program) and the power plan (plan). During the development of the program, physical and economic impacts of each fish and wildlife measure affecting the operation of the hydroelectric system were assessed and considered before final adoption of the program. In the current effort to produce the Fifth Northwest Power Plan, the Council assumes that measures in the program will be implemented. Strategies for new resource and conservation development incorporate the relationship between non-hydro resources and the operation of the hydroelectric system, which include measures for fish and wildlife.

It is not possible in the context of this power plan to compare on an equivalent basis the power system costs and benefits of specific fish operations or deviations from those operations with the corresponding biological costs and benefits. The Council in its fish and wildlife program has recommended that fish measures be examined for their cost-effectiveness. The program dictates that if the same biological objectives can be met at less cost, those less costly means should be pursued.

Outside of the Council, however, no clear process exists for integrated long-term planning for both fish and power. Under the Endangered Species Act (ESA), NOAA Fisheries and the U.S. Fish and Wildlife Service share the responsibility to assess the status of listed species and to develop a recovery plan, often referred to as a biological opinion. Language in the ESA specifies that economic impacts should not play a role in the development of the biological opinion. This has led to some costly measures that arguably provide marginal biological benefits. In particular, the question of summer bypass spill for juvenile migrants has been fiercely debated over the past several years.

As a practical matter, federal agencies have formed several committees through the biological opinion process to deal with in-season operational issues affecting fish and power. The Technical Management Team (TMT) consists of technical staff from both federal and non-federal agencies that usually meet on a weekly basis to assess the operation of the hydroelectric

[1] "Optimizing" here means that energy production is maximized, limited by other than fish and wildlife constraints, such as flood control, irrigation, navigation, etc.

system. Requests for variations to those operations can be made and discussed at TMT meetings. Conflicts that cannot be resolved at the technical meetings are passed on to the Implementation Team (IT), which consists of higher policy-level staff. Impasses not resolved by this group are forwarded to the Executive Committee (EC), made up of executive staff from the various participating organizations. The process of resolving conflicts in proposed hydroelectric operations can sometimes be lengthy and cumbersome.

Recommendation -- Better Integration of Planning Efforts

While the existing committee structure can usually solve in-season problems, no currently active process exists to address long-term planning issues. The Council recommended in its 2000 program that both in-season and annual decision-making forums be improved.[2] The program states "at present, this decision structure is insufficient to integrate fish and power considerations in a timely, objective and effective way." It goes on to recommend that the forums should broaden their focus by including "expertise in both biological and power system issues" and by directly addressing longer-term planning concerns, not just weekly and in-season issues.

It is in such a forum where the long-term physical, economic and biological impacts of a fish and wildlife operation can be openly discussed and debated. Actions identified in the program to benefit fish and wildlife "should also consider and minimize impacts to the Columbia basin hydropower system if at all possible." The program further says that the goal should be "to try to optimize both values to the greatest degree possible."

To this end, the Council reiterates its recommendation in the 2003 program to improve and broaden the focus of the forums created to address issues surrounding fish and wildlife operations, especially those related to long-term planning.

Limits on Integration

Given the current status of biological information and considering the irresolvable task of assigning a dollar value to preserving salmon runs, a total integration of power and fish-and-wildlife planning is impossible. However, that does not mean that these processes must be done independently of each other. Power system planners can provide valuable information to fish and wildlife managers to aid their development of measures to improve survival. Similarly, fish and wildlife managers can provide data to power planners so that they can plan for resource mixes that minimize impacts to fish and wildlife, whenever possible.

Biologists developing a fish and wildlife program must be able to assess relationships between various physical parameters and survival. For example, river flows, water temperature, passage routes (turbines, bypass or barges), predation, ocean conditions and a host of other factors all affect survival and long-term population forecasts for salmon. Based on these relationships, biologists can make recommendations regarding those elements that can be controlled, such as the operation of the hydroelectric system. Any changes to the operation of the hydroelectric system will result in differences in reservoir elevations, river flows, energy production and cost.

[2] "Fish and Wildlife Program," Northwest Power Planning Council, Council Document 2000-19, pp.28, and "Mainstem Amendments to the Columbia River Basin Fish and Wildlife Program," Northwest Power Planning Council, Council Document 2003-11, pp.28-29.

Using sophisticated computer models that simulate the operation of the Northwest power system, power planners can assess the impacts of any given set of fish and wildlife measures that change the operation of the hydroelectric system. For a fish and wildlife program and, in particular, for individual elements of that program, physical impacts (effects on reservoir elevations and on river flows) and economic impacts (changes in generation production and related cost) can be analyzed and provided to fish and wildlife managers.

Changes in reservoir elevations, river flows and spill are used, along with other data, by biologists to estimate fish passage survival through the system. Passage survival estimates are an important part of life-cycle models, which are used to forecast long-term fish populations. Long-term population estimates, along with their corresponding uncertainties, will determine whether certain species are well off, stable or declining. So, in this sense, physical analysis by power planners plays a very important role in the development of a fish and wildlife program.

Economic data should also be very important to biologists. There will always be a need to refine our understanding of the relationships between survival and changes in the physical environment. Unfortunately, there is never sufficient research money to perform all desired experiments and tests. By knowing how much individual measures in a fish and wildlife program cost, biologists will have a better idea of how to spend limited research money. Measures that are most costly and have large uncertainties surrounding their biological benefits would make the best candidates for research money.

In addition to aiding biologists to spend research money more effectively, economic data can be used to reduce the total cost of a fish and wildlife program. In cases where two different measures provide the same biological result, it makes sense to implement the least costly operation. Practically speaking such decisions are rarely simple to make because of the uncertainty surrounding biological benefits. However, just as power planners are obliged to provide an adequate power supply at the lowest cost, it seems appropriate that biologists should at least attempt to develop the least-cost program that achieves their biological objectives.

Economic impacts of fish and wildlife measures also help biologists in other ways. The biological opinion contains specific language that allows for curtailment of fish and wildlife operations in the event of a power emergency. Such an event occurred in 2001 that was severe enough to result in most bypass spill being curtailed (more on that subject in the following section). Had that event not been so severe, necessitating the need to curtail only some operations, the region would have had to scramble to determine which measures to curtail. To avoid such a situation in the future, an emergency curtailment policy should be established. Having cost and biological impacts for individual measures allows biologists to prepare such a policy and have it in place prior to a power emergency.

Appendix XX provides more background information regarding those elements of the fish and wildlife program that affect the operation of the hydroelectric system and their impacts to the power system.

Other Considerations

As the years of 2000 and 2001 unfolded, analyses by the Council and others indicated that fully implementing the 2000 Biological Opinion (BiOp) mainstem hydroelectric operations in 2001 was likely to compromise power system reliability. This was due to very dry conditions in that year and the basic state of the power supply in the Northwest and in the rest of the Western interconnected system. Allowances in the BiOp, however, permit the curtailment of fish and wildlife operations during power emergencies. The Bonneville Power Administration (Bonneville) declared a power emergency in that year based on the water supply and the lack of available generation on the market. Decisions were made to severely reduce bypass spill during the spring and summer months in order to ensure adequate supplies of power and to manage the economic impact of the high market prices. This action initiated a regional debate regarding the additional risk placed on endangered or threatened fish and what measures could be taken to avoid or reduce the likelihood of such events occurring in the future.[3]

In our society, money usually is the common denominator. The dollar value of power operations is easily quantifiable whereas the dollar value of fish recovery is much harder to quantify, both in terms of the uncertainty regarding the biological impact of certain power system actions and the ability to compare the biological impacts with power system impacts in comparable terms. There will always be significant financial incentives to deviate from prescribed fish operations when power supplies become tight and prices soar, especially if supporting biological data has a high range of uncertainty. The concern is that fish and wildlife survival may be inadvertently jeopardized for financial reasons, using the "power emergency" section of the BiOp as a surrogate to building a reliable and economic power system.

Reliability and cost are directly related. In the Northwest, electric utility planners have relied on the inherently large capacity of the hydroelectric system to keep costs low while maintaining a high level of reliability. Because the BiOp language allows for curtailment of fish and wildlife operations during emergencies, it implies that fish and wildlife measures will not be implemented at "all costs." It does not, however, imply that fish and wildlife operations can be used in lieu of developing an adequate power supply. With this in mind, it may be appropriate for the region to consider developing a metric to quantitatively assess how successful the power system is in providing operations for fish and wildlife (or conversely, a metric to assess how often those operations would be curtailed due to power emergencies).

Ultimately, an adequate power supply also adequately provides for fish and wildlife operations. Determining that we have an adequate power supply means analyzing how often that supply is insufficient. This is tabulated in a metric commonly referred to as a loss of load probability (LOLP). Perhaps a similar type of metric can be developed to assess the likelihood of failures to provide fish and wildlife operations. Whether a metric is developed or not, the Council has the responsibility to assure the region that its plans provide both an adequate power supply and operations to protect fish and wildlife adequately.

[3] See the Council's account of the events of 2000-01. [Put link or reference here.]

The Future Role of the Bonneville Power Administration in Power Supply

Introduction

The crown jewel of the Northwest Power System is the federal Columbia River Power System (FCRPS). The FCRPS consists of 31 dams on the Columbia River and its tributaries. On average, it supplies approximately 45 percent of the region's power. This federal hydropower is priced at cost and is sold by the Bonneville Power Administration primarily to publicly owned electric utilities. While the federal government financed construction of the FCRPS, the debt is repaid by Northwest electricity users. Interest rates on the federal debt are now equal to market rates.

Despite the fact that Bonneville has not deferred any payments to the U.S. Treasury since the early 1980s, it is continually attacked by organizations like the Northeast-Midwest Institute[1] and its congressional allies as being subsidized by the federal government. Critics advocate privatizing Bonneville or requiring Bonneville to sell its power at market prices to benefit U.S. taxpayers as opposed to selling at cost to Northwest consumers who paid for the system and are paying to restore fish and wildlife affected by the dams. While these proposals have not yet gained sufficient political support to move ahead, fighting them has been a continuing battle for Bonneville, the region's utilities, governors, the Council and the congressional delegation. Moreover, each time Bonneville finds itself in financial difficulties with Treasury repayment at risk, the pressure for "reform," such as privatization, intensifies.

Over the last decade, the difference between the cost of Bonneville's power and market rates for wholesale power has frequently not been large. In fact, at some times it has been disadvantageous to Bonneville's customers. Nonetheless, the existing system of federal hydropower is likely to be a low-cost resource for many years to come. Preserving this benefit for the Northwest consumers who pay for it should be a high priority for the region. However, preserving the benefit in the face of recurring financial crises at Bonneville will be difficult.

Bonneville's financial vulnerability arises in part from its dependence on a highly variable hydroelectric base and the effects of a sometimes very volatile wholesale power market. Another source of vulnerability arises from the uncertainty created by the nature of the relationships between Bonneville and many of its customers and how Bonneville has historically chosen to implement its obligations. These vulnerabilities are exacerbated by Bonneville's high fixed costs for its debt on the Federal Columbia River Power System and the three nuclear plants that were undertaken with Bonneville backing by the Washington Public Power Supply System, now Energy Northwest.[2] At times, these vulnerabilities can cause Bonneville to incur high costs that must be passed on to customers and ultimately to the region's consumers. If those costs are not passed on to customers, Bonneville risks being unable to make Treasury payments. Rate increases cause economic hardship in the region; not making a Treasury payment risks a political

[1] E.g. see *Rethinking Bonneville – Why BPA Must Be Reformed*, Richard Munson, Northeast-Midwest Institute, 2001, http://www.nemw.org/rethinkingbonneville.pdf

[2] Of the three plants, only one, Columbia Generating Station, is operating. The other two were terminated before construction was complete. However, Bonneville still has responsibility for paying off the debt incurred during construction.

backlash from outside the region that could cause the Northwest to lose the long-term benefits of power from the federal system.

As noted above, one source of Bonneville's financial vulnerability is the uncertainty created by the nature of its relationship with its different customer groups. For example:

- Bonneville has a legal obligation to sell power to publicly owned utilities at cost if asked. However, Bonneville's public customers do not have a legal obligation to buy from Bonneville until they have signed a contract. And even then, customers have had some success at getting relief from their contractual obligations.
- Bonneville does not have a legal obligation to sell to the direct-service industries, but there are powerful political and local economic pressures to do so.
- For investor-owned utilities, Bonneville has an obligation to provide benefits to existing residential and small farm customers but has struggled to find a means of doing so that is satisfactory to all parties. It also has a legal obligation to meet the load growth of investor-owned utilities if requested although no such requests ever have been made.

How Bonneville has historically carried out its responsibility in power supply has also been a source of vulnerability. It has served the net requirements of its preference customers and DSIs at "melded" rates, i.e. it has averaged costs of the low-cost existing federal system with that of more expensive new resources required to meet loads beyond the capability of that system. This has had several adverse effects:

- It frequently had the effect of making Bonneville's power appear inexpensive relative to the cost of the new resources needed to serve growing loads. This can attract loads to Bonneville that might be more efficiently served in other ways.
- It has diluted the benefits of the low-cost existing system and, when wholesale power prices are low, has made Bonneville appear uncompetitive.
- This artificially low cost has been a disincentive for utility investment in cost-effective conservation and local generating options.

These issues have been the topic of several public and internal processes over the last decade. These include: the Comprehensive Review of the Northwest Energy System, carried out in 1996 in response to a request from the region's governors; the follow-on Bonneville Cost Review; the Joint Customer Proposal of 2002 and the subsequent Regional Dialogue and Council recommendations; an internal Bonneville review of the lessons learned from the 2001 electricity crisis; and, most recently, the Regional Dialogue discussions in the fall of 2003 and early 2004.[3]

The recommendations coming from these processes have several common elements:

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[3] *Comprehensive Review of the Northwest Energy System -- Final Report: Toward a Competitive Electric Power Industry for the 21st Century,* Comprehensive Review Document CR 96-26, December, 1996. http://www.nwcouncil.org/library/1996/cr96-26.htm; *Cost Review of the Federal Columbia River Power System -- Management Committee Recommendations,* Document CR 98-2, March 10, 1998. http://www.nwcouncil.org/library/1998/cr98-2.htm; *Investor-Owned Utility/Preference Utility Proposal For The Future Role Of The Bonneville Power Administration,* October 29, 2002 draft; *What Led to the Current BPA Financial Crisis? A BPA Report to the Region,* also known as "The Lessons Learned" report, Bonneville Power Administration, April 2003; *Northwest Power Planning Council Recommendations on the Future Role of Bonneville in Power Supply,* Council Document 2002-19, December 17, 2002. http://www.nwcouncil.org/library/2002/2002-19.htm; *The Future Role of Bonneville in Power Supply*, Council Document 2003-18, October 2003, http://www.nwcouncil.org/library/2003/2003-18.htm

- Bonneville should sell the federal power through long-term contracts (20 years) to reduce uncertainty and help protect the region from external efforts to appropriate the benefits of the FCRPS.
- A means should be found of satisfying Bonneville's obligation to provide benefits to the residential and small farm customers of the region's investor-owned utilities that is equitable and predictable.
- Bonneville's and the region's exposure to risks of the wholesale power market should be limited, and clarity regarding responsibility for meeting load growth should be improved by limiting Bonneville's role in serving loads beyond the capability of the FCRPS.

The time to resolve these issues is now

Most Bonneville customers' contracts do not expire until 2011. Nonetheless, there is relatively little time to resolve issues and implement solutions. Commitments to new resource development will have to be made in the latter part of this decade. If uncertainty regarding how Bonneville will carry out its role in power supply persists, needed resource development could be impeded. The Bonneville Power Administration has announced it will carry out a policy process during the summer and fall of 2004, primarily to resolve issues related to the last five years under the current contracts. Many of the issues, however, relate to Bonneville's longer-term role. The Council has urged Bonneville to use this opportunity to establish a schedule for making decisions about its longer-term role that will permit it to offer new contracts by October of 2007. While the new contracts need not be effective until 2011, having new contracts in place by 2007 will provide Bonneville and its customers the certainty the need to undertake resource actions.

Council Recommendations

The Council has made recommendations to Bonneville regarding its future role in power supply. The recommendations were made with the following goals in mind:

- Preserve and enhance the benefits of the Federal Columbia River Power System for the Northwest;
- Not increase and, preferably, reduce the risk to the U.S. Treasury and taxpayers;
- Achieve an equitable sharing of the benefits of the federal power system;
- Develop and maintain widespread support for the federal system and reduce conflicts within the region;
- Align the costs and benefits of access to federal power;
- Maintain and improve the adequacy and reliability of the Northwest power system;
- Make clear who will be responsible for meeting load growth and on what terms;
- Provide clear signals regarding the value of new energy resources;
- Lessen Bonneville's exposure to market risk;
- Lessen Bonneville's impact on the market;

- Satisfy Bonneville's responsibilities for conservation and renewable resource development;
- Satisfy Bonneville's responsibilities with respect to fish and wildlife; and
- Accomplish all these goals efficiently and at as low as possible a cost to the region's consumers.

The Council's recommendations are presented in full in Appendix??. The key recommendations are described below.

A fundamental change in how Bonneville carries out its role in power supply

Resolving the problems that have afflicted Bonneville and the region requires a fundamental change in how Bonneville executes its role in power supply consistent with the Northwest Power Act of 1980 (the Act). Under the Council's recommendations, Bonneville would sell electricity from the existing Federal Columbia River Power System to eligible customers at its cost. Customers that request more power than Bonneville can provide from the existing federal system would pay the additional cost of providing that service. This change would clarify who would exercise responsibility for resource development; it would result in an equitable distribution of the costs of growth; and it would prevent the value of the existing federal system from being diluted by the higher costs of new resources. This change in role ultimately should be implemented through long-term (preferably 20-year) contracts and compatible rate structures.

This change in Bonneville's future role *does not* alter Bonneville's fundamental responsibility to serve the loads of those qualifying customers who choose to place load on Bonneville; it *does not* alter Bonneville's responsibility for ensuring the acquisition of Bonneville's share of all cost effective conservation and renewable power identified in the Council's Northwest Power and Conservation Plan (Plan); and it *does not* alter Bonneville's responsibility to fulfill its fish and wildlife obligations under the Act and the Council's fish and wildlife program. It *does* represent a change in the way Bonneville traditionally has carried out those responsibilities.

Define a clear and durable policy framework for contracts and rate-making

The Council believes that debate in the region over the future role of Bonneville is less about the end-state, a limited role for Bonneville in power supply, than about how to reach that end-state. The Council acknowledges that both new long-term contracts and a revised pricing structure will be necessary to fully implement a new role for Bonneville. The Council believes, however, that a clearly articulated and durable policy regarding Bonneville's future role must guide the necessary contract negotiations with customers and future rate cases.

The Council remains concerned that the policy process Bonneville is planning to undertake will not provide the durability necessary to meet expectations for long-term contract negotiations and associated rate processes, and the region's expectations for conservation and renewable resource development. To improve the durability of the policy, it must include clear identification of the priority issues that are to be resolved, the process by which they will be addressed, and an aggressive schedule for doing so. That schedule should result in offering new long-term contracts by October of 2007.

If this process proves incapable of resolving issues within the established schedule, alternative processes should considered. Bonneville and the Council should first determine if substantive rulemaking can be a vehicle for resolving the outstanding issues. If rulemaking is considered inappropriate, Bonneville and the Council should work together to identify specific legislation and seek comments from the public. Legislation should not be considered if there is not broad regional support including consensus among the region's governors.

Offer long-term contracts as soon as possible

Only long-term contracts will provide the certainty, continuity, and durability that customers need to make long-term resource commitments; the stability that Bonneville needs to be able to ensure Treasury repayment; and the protection the region needs for one of its most significant assets. Bonneville should offer such contracts no later than October of 2007.

The biggest impediment to long-term contracts is that Bonneville's customers are concerned they would lose the major means by which they can exercise discipline on Bonneville's costs and business practices – their ability to take load off Bonneville. Because long-term contracts have benefits for the parties and the entire region, all parties need to be open to examining ways to overcome concerns such as allocation of power, cost segregation, cost control, contract enforceability, dispute resolution, Bonneville business practices in general, and possible adverse impacts to Bonneville's public service responsibilities under the Act. The Council commits to work with Bonneville, its customers, and others to identify a workable resolution of problems that may arise.

Allocation of the existing system

Fundamental to implementing changes in Bonneville's role in power supply is allocating the power from the existing federal system among eligible customers. Any allocation should be done in such a way as to minimize opportunities for gaming the process.

Tiered rates under existing contracts?

Tiered rates would be the clearest practical indication of how Bonneville will be carrying out its role in the future.[4] If Bonneville defines its role as the Council recommends, and if critical issues are resolved in a timeframe consistent with the schedule established in Bonneville's policy; and if new contracts are negotiated and offered by October of 2007; then the Council would not press for tiered rates under the current contracts for the next rate period. However, the Council reserves the right to reconsider this recommendation if those conditions are not met.

Products

Customers should have access to the full range of products that are currently available, such as requirements, block, and slice products. Importantly, the costs of each product should be confined to the purchasers of that product. Every effort should be made to eliminate cross-subsidies among products. In the process of negotiating new contracts, customers should have the opportunity to choose the products that best meet their needs.

[4] In this context, tiered rates mean a rate structure in which the rate charged for the first tier reflects the cost of the resources in the existing federal power system and the rate charged for the second tier reflects the cost of resources acquired to meet requirements beyond the capability of the existing system.

Direct Service Industries (DSIs)

If a DSI has been a responsible customer of Bonneville, there may be an opportunity to provide a limited amount of power for a limited duration under specified terms and conditions. The existing federal system is roughly in load/resource balance. Consequently, some level of augmentation probably will be necessary to provide reasonably continuous service. If power is to be made available to DSIs, the amount and term should be limited; the cost impact on other customers should be minimized; and Bonneville should retain rights to interrupt service for purposes of maintaining system stability and addressing temporary power supply inadequacy.

Benefits for the residential and small farm customers of investor-owned utilities

The Council strongly supports resolution of the issue of benefits for the residential and small-farm customers of investor-owned utilities (IOUs) for a significant period. The Act established a mechanism for sharing benefits of access to low-cost federal power. That 24-year-old mechanism has operated in such a way that it satisfies no one. However, "fixing" that feature of the Act through legislation could have broad ramifications. The Council favors a long-term settlement that provides benefits in the form of dollars. The Council cannot judge what is an equitable settlement. However, the necessary characteristics of a settlement can be defined. A settlement must provide certainty, it must be transparent, and it must not be subject to manipulation. The proposed settlement that collapsed in early 2004 contained these elements and was supported by nearly all of Bonneville's Northwest customers. The Council believes this could be the template for a long-term settlement.

Fulfilling responsibilities for conservation and renewables

The Council expects Bonneville and the region's utilities to continue to acquire the cost-effective conservation and renewable resources identified in the Council's power plans. Bonneville should employ mechanisms similar to the current Conservation and Renewables Discount (C&RD) program and provide essential support activities to encourage and facilitate utility action. Bonneville's role will be substantially reduced to the extent that customers can meet these objectives. But if necessary, Bonneville must be prepared to provide a backstop mechanism to ensure that these objectives are met. Bonneville must retain the ability to secure its regional share of cost-effective conservation and renewables identified in the Council's power plan that are not otherwise secured by its customers. The costs of the backstop actions would be paid by utilities that fail to meet their responsibilities. The C&RD program has been instrumental in motivating many utilities to pursue conservation and renewables activities. But the rate discount needs to be refined as outlined in the Council's December 2002 recommendations on the future role of Bonneville. The focus needs to be on determining how to reliably acquire all the cost-effective conservation at the lowest cost to the utility system. Bonneville and the Council should facilitate a collaborative process to refine the details of a rate discount and produce recommendations by early 2005.

However, a rate discount should not necessarily be the only mechanism available to encourage utilities to acquire conservation and renewable resources. There are a number of activities that can be carried out more effectively if they are approached on a coordinated regional basis with local implementation. These include activities like market transformation, limited development and demonstration activities, and program design and administration where there are significant economies of scale to be gained. Bonneville should continue these activities and, in addition, its support of low-income weatherization.

The Council continues to believe that levels of renewable resource development should be guided by the Council's Plan. The C&RD could be used to support customer acquisition of renewable resources so long as cost-effective conservation is also acquired.

Bonneville is uniquely suited to pursue some renewable resources development that would not happen without its participation. These activities benefit all of Bonneville's customers, and their costs should be recovered from the existing system. These include activities such as: 1) removing barriers to cost-effective renewable resource development; 2) developing storage and shaping services, developing transmission re-dispatch products and making transmission acquisition for renewable resources easier; and 3) limited, region-specific research and demonstration. The costs of providing services like storage and shaping should be paid by the purchaser.

With regard to acquiring the output of new renewable resources, the Council believes Bonneville's activities should be consistent with the Plan. Bonneville should acquire new renewable output to meet new or replacement resource needs placed on the agency, provided resources are cost-effective after accounting for any risk reduction or other benefits the resources provide. The Council encourages those utilities that choose to take responsibility to meet their own load growth to use their best efforts to acquire renewables consistent with the Council's Plan and for Bonneville to use its capabilities to facilitate such acquisitions.

Resource adequacy

Even without changes in the way Bonneville carries out its role in power supply, the issue of resource adequacy, and the possible need for an adequacy standard or target to ensure that adequate power supplies are maintained, has been a major concern of the Council and others in the region. A change that results in more of the risk and responsibility of meeting future load obligations being borne by individual utilities instead of by Bonneville does not reduce overall risk. The Council is aware that new policies may be necessary to ensure that adequate information and safeguards exist to determine the power system's adequacy. In particular, the Council is concerned about the possibility that a severe deficit by any one utility could have detrimental effects on other utilities in the region. This risk can only be removed if all utilities ensure an adequate level of resources for their own load-serving responsibilities.

The Council is committed to working with Bonneville, utilities, the states, regulatory commissions, and other regional and West-wide organizations to ensure that appropriate adequacy policies are in place and that the data and other tools to implement the policies are available. The Council believes these policies need to be in place prior to the implementation of long-term contracts.

Fulfilling responsibilities for fish and wildlife

The Council believes these recommendations will not affect Bonneville's fish and wildlife obligations. Those obligations will be determined in a manner consistent with the requirements of the Act and the Council's Columbia River Basin Fish and Wildlife Program. Bonneville's mitigation costs should be allocated to the existing federal power system.

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