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 the power plants was completed, the costs of these 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.

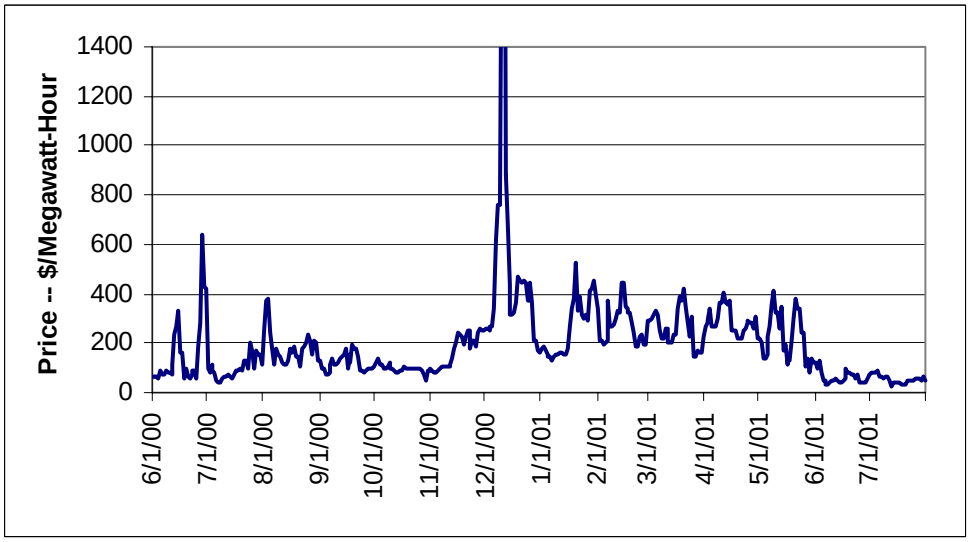

Figure 1-1 – Daily Average Firm Prices at Mid Columbia

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).

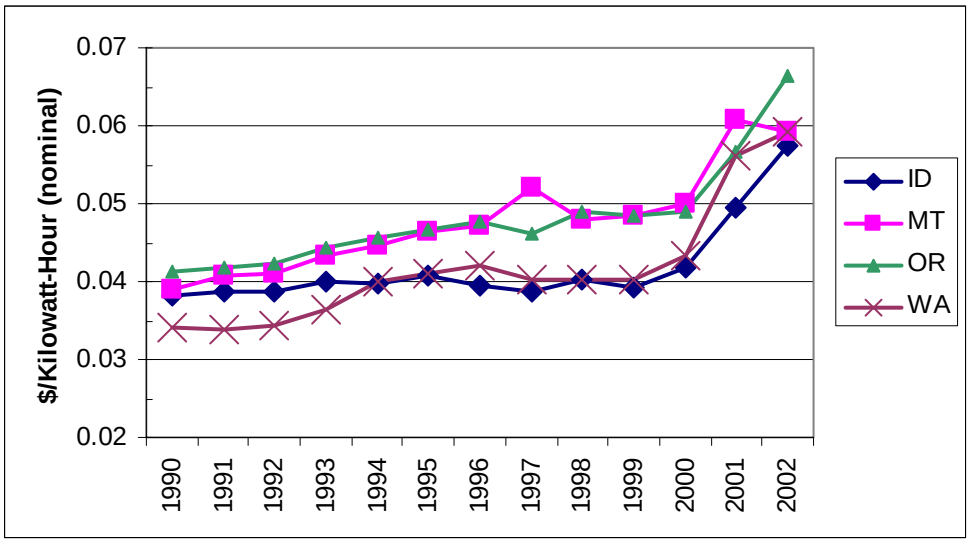

Figure 1-2: Average Retail Rates – All Sectors

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.

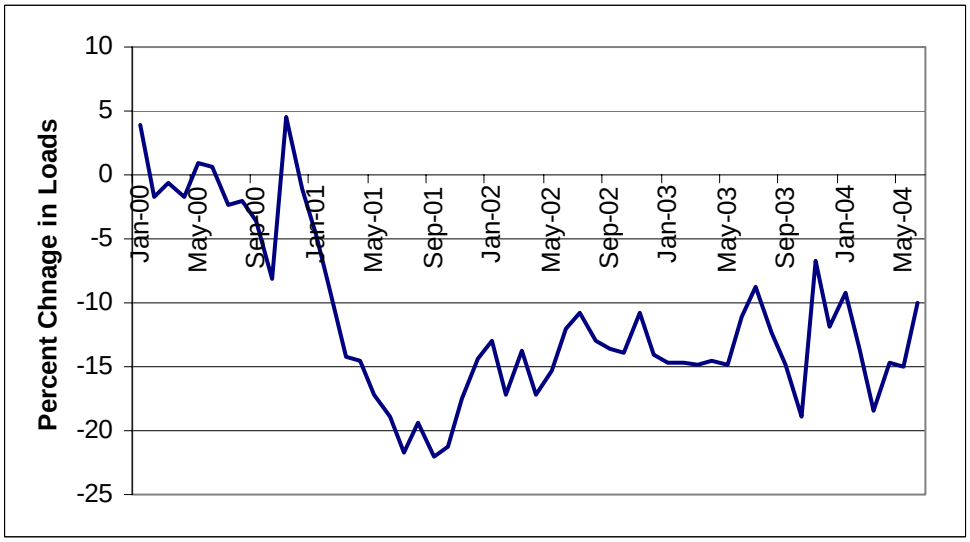

Figure 1-3: Percent Change in Regional Loads from Same Month in 1999

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.

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 since 1929. 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 were 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 critical water load-resource balance was increasingly negative (loads greater than regional resources) throughout the 1990s (Figure 1-4).[2] 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.

[2] "Critical water" is the historical volume and temporal pattern of river flows that results in the lowest energy production from the hydropower system.

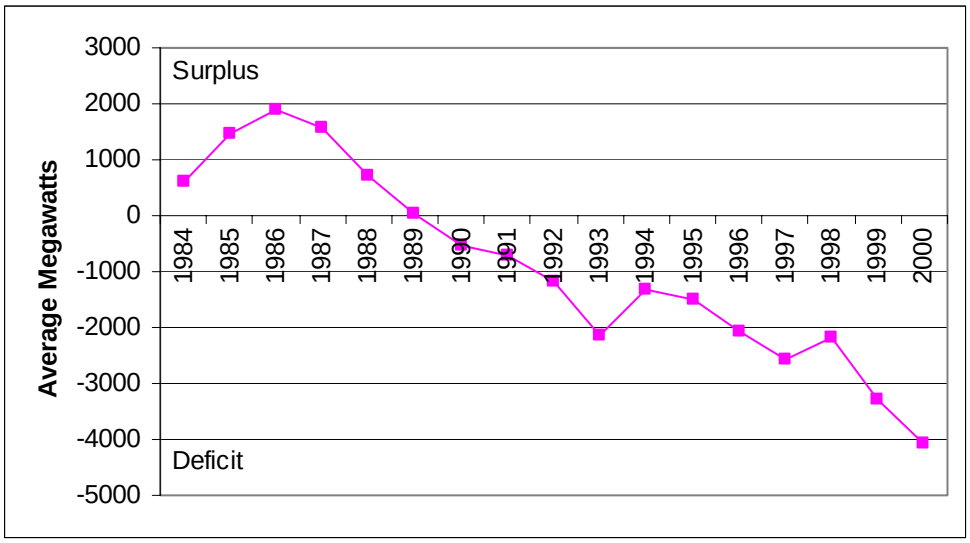

Figure 1-4: Northwest Load/Resource Balance – Critical Water

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 (the "loss of load" probability) 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.[3] 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. 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?

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 would 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

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

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.

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 fully 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 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, by then 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 was 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. 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. An additional 1,400 megawatts is partially complete, although construction has been suspended. With the exception of approximately 500 megawatts of wind, the great majority of the generation 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 began falling in late 2000. By 2002, loads were 2,800 average megawatts below loads in 2000 on an average annual basis, a drop of 13 percent.[4] This load reduction was accomplished through two means: efficiency and, primarily, demand response.[5]

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

[4] Demand reductions on a monthly basis were even more dramatic. July 2001 loads were 4,675 average megawatts lower than the same month in 1999, a 22 percent reduction.

[5] "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."

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 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, 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 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 fewer loads exposed to the high prices.

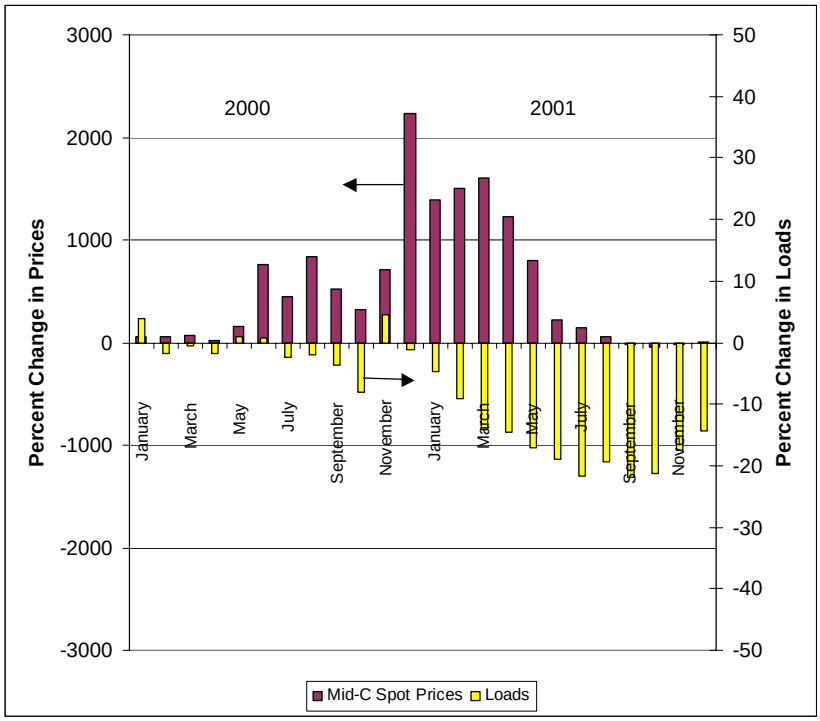

Figure 1-5: Percent Change in Mid-Columbia Spot Prices and Northwest Loads from Same Month in 1999

Hydro Operations

The third leg of the 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:

1. Resource Planning and Adequacy
   - The region puts in place resource adequacy standards or targets and the necessary 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.
2. Market Rules and Regulation
   - 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.
- 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.

3. Conservation, Renewables and High Efficiency Resources
   - The region continues to pursue and acquire cost-effective conservation, renewables and high efficiency resources through regional, Bonneville, utility and state programs that supplement competitive market incentives where necessary.
4. Fish and Wildlife
   - The region fulfills its fish and wildlife protection and mitigation responsibilities as they relate to the hydroelectric system effectively and efficiently.
5. The Bonneville Power Administration
   - 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 conservation and bilateral, incrementally priced contracts with individual customers or groups of customers.

Focus for the Fifth Power Plan

The Fifth Power Plan can help the region achieve this vision. The challenge for the Fifth Power Plan is two-fold. The first relates to 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-effective 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 and efficiently; 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 program 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, the potential amount 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 2-1). 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 2-1, 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.

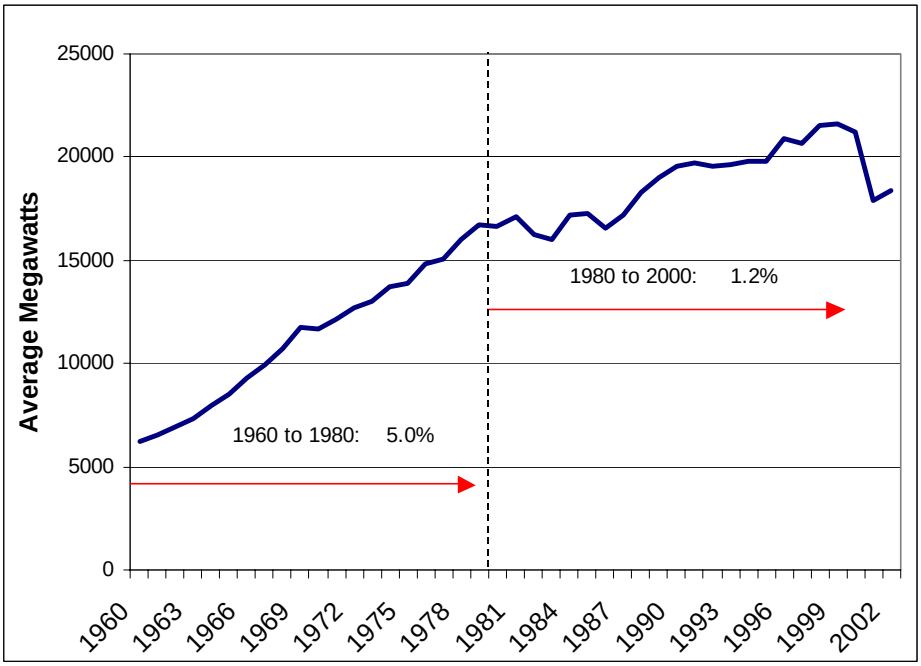

Figure 2-1: Forty-Three Years of Pacific Northwest Electricity Demand

Table 2-1: 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. 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 1,800 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 2-2 illustrates this

price history.[1] 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 electricity 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 2-1.

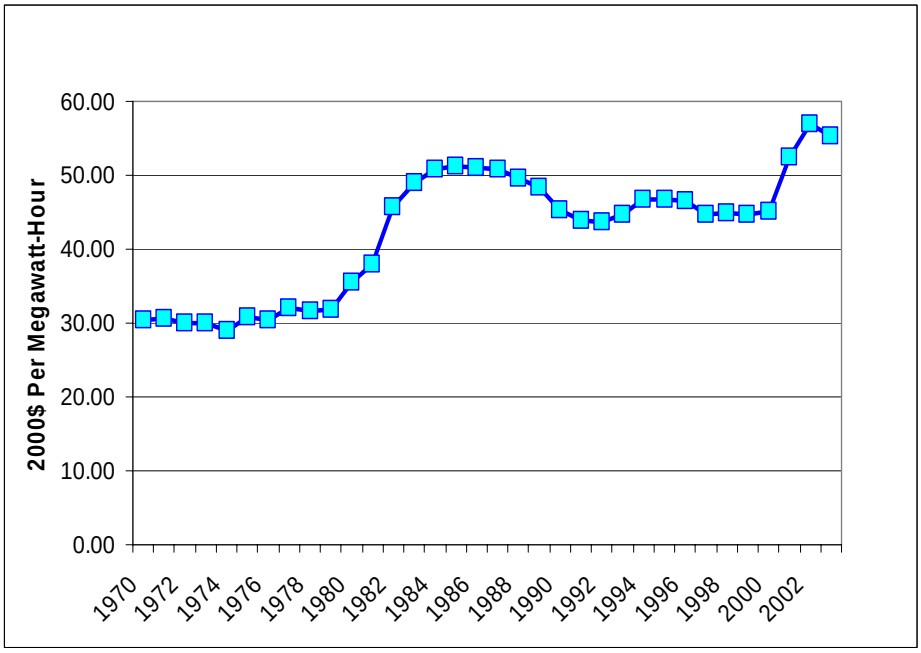

Figure 2-2: Historical Retail Electricity Prices in the Pacific Northwest

Average annual 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 and 2004 does not indicate a significant recovery 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 A. Table 2-2 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

[1] Prices in Figure 2-2 are expressed in constant year 2000 dollars as are many other tables and graphs throughout the plan. In the Executive Summary and Overview and in Chapters 6 and 7 constant dollar prices are expressed in year 2004 dollars. To convert from constant 2000-dollar prices to constant 2004 dollar prices multiply by 1.0776, which is a measure of the general inflation between 2000 and 2004.

consumption are reached again. The range of forecasts reflects significant uncertainty about demand trends.

Uncertainty in long term demand trends, as shown in Figure 2-3, define only a part of the uncertainty in demand that is evaluated in the portfolio analysis. The portfolio model adds variations to reflect seasonal patterns, business cycles, and weather sensitivity. In addition, the demand of electricity for aluminum smelting is treated separately and is assumed to depend on variations in aluminum prices and electricity prices

Table 2-2: Demand Forecast Range[2]

	(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 2-3 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.

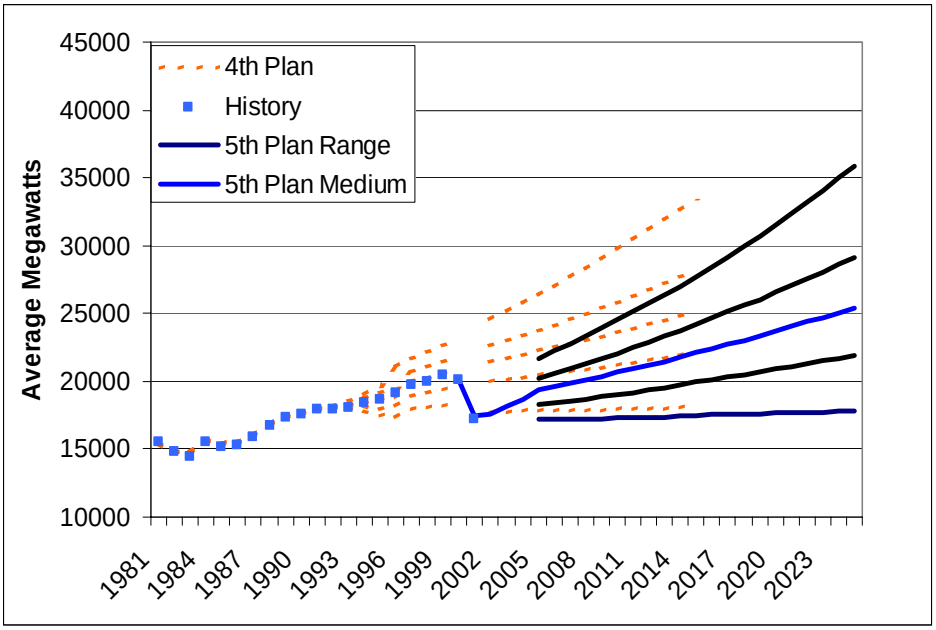

Figure 2-3: Demand Forecast Range Compared to History and Council's Fourth Power Plan

[2] Figures are electricity use by consumers and exclude transmission and distribution on losses.

REGIONAL ELECTRICITY SUPPLY

The region's electricity supply is still dominated by hydroelectric power. Hydroelectricity 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, 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. The total annual energy generating capability in the region under critical water conditions (including non-hydro resources), is estimated to be about 23,000 average megawatts. In reality, the region has probably departed informally from critical water standards for a decade or more.

Figure 2-4 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.

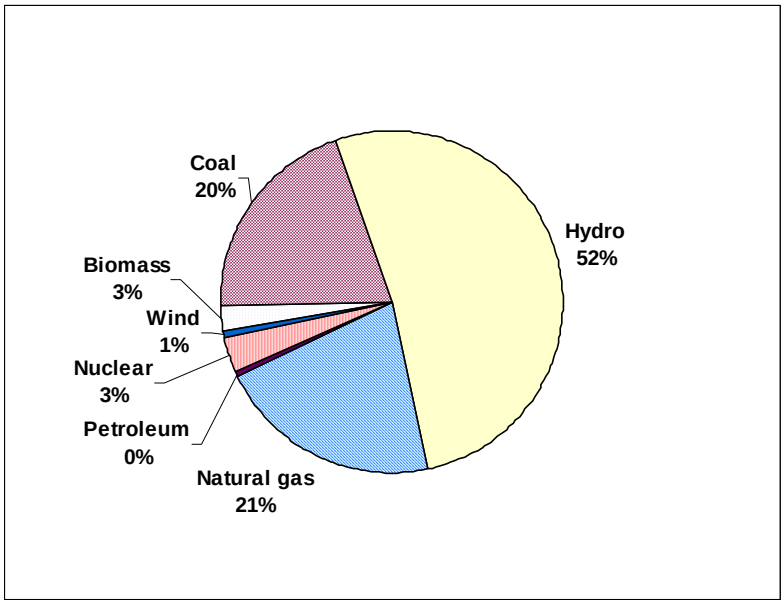

Figure 2-4: Sources of Pacific Northwest Electrical Energy Generation

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[3] of the hydro system, for example, is 5,400 megawatts less than its nameplate capacity.

[3] 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).

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 2-5 illustrates how the mix of regional electricity generation has changed over time. 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 uncertainties and risks facing the region.

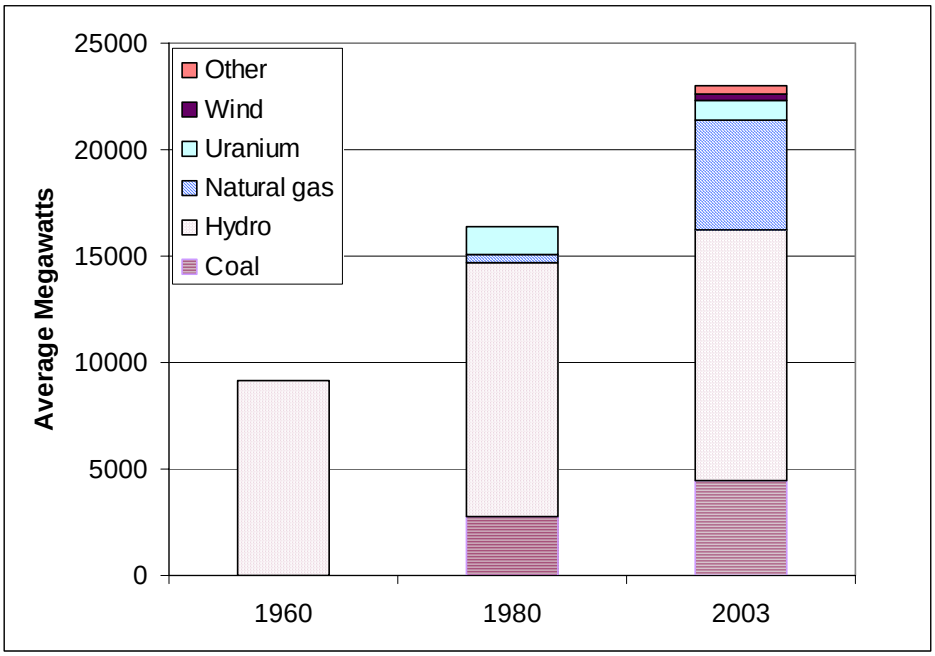

Figure 2-5: Changing Pacific Northwest Sources Electricity Generation

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 smelters, 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.

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 2-4 or 2-5. The Council has estimated that the region has acquired 2,200 average megawatts of end-use conservation through 2002, the

equivalent of about 2,500 average megawatts of electricity generation.[4] Approximately 25 percent of the resources added in the Northwest since 1980 have been conservation.

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 megawatts 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.

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 1,500 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, as 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 2002. During the same time, new generating resources were added that increased energy capability by about 3,500 average megawatts.

Figure 2-6 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 2014. 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 2015 and beyond, but with medium-high demand growth the region is somewhat deficit after 2008.

However, not all the resources included in Figure 2-6 are contractually committed to regional loads. Independent power producers (IPPs) own most of the current surplus. For the period 2005 through 2008, only 950 out of 3600 megawatts of IPP capacity are contractually committed to regional loads. Beyond 2008, that figure drops to 430 megawatts.[5] The rest is available for short-term sales.

As of this writing, none of the IPP generation is committed on a firm basis to loads outside the region through 2008 and beyond. Making long-term firm sales out of the region would be difficult or impossible because of a lack of firm transmission access. Therefore, we assume that these resources would be available to meet Northwest loads. However, unless these resources are purchased or contracted for on a long-term basis, their power will be priced at the market.

[4] The difference is attributable to transmission and distribution system losses that affect generation.
[5] Data from survey of membership of Northwest Independent Power Producers Coalition, June 8, 2004.

Because the IPP power is assumed to be purchased at market prices, it makes little difference in terms of the cost of power to the region whether or not these IPP plants are contracted out of the region. Because the amounts of generation and demand in the western electricity market would not change, the electricity market price would not change. Therefore, whether the region purchases energy from the market, or from the IPP plants, the price would be the same. The balance of loads and resources for the Pacific Northwest as compiled in Figure 2-6 does not include the possibility of purchases from the wholesale market. The sale of the IPP power outside the region would reduce regional resources and reduce the surplus shown in the graph. However, if the reduction in resources were replaced by purchases in the wholesale electricity market, the regional energy cost and reliability situation would be little changed in reality.

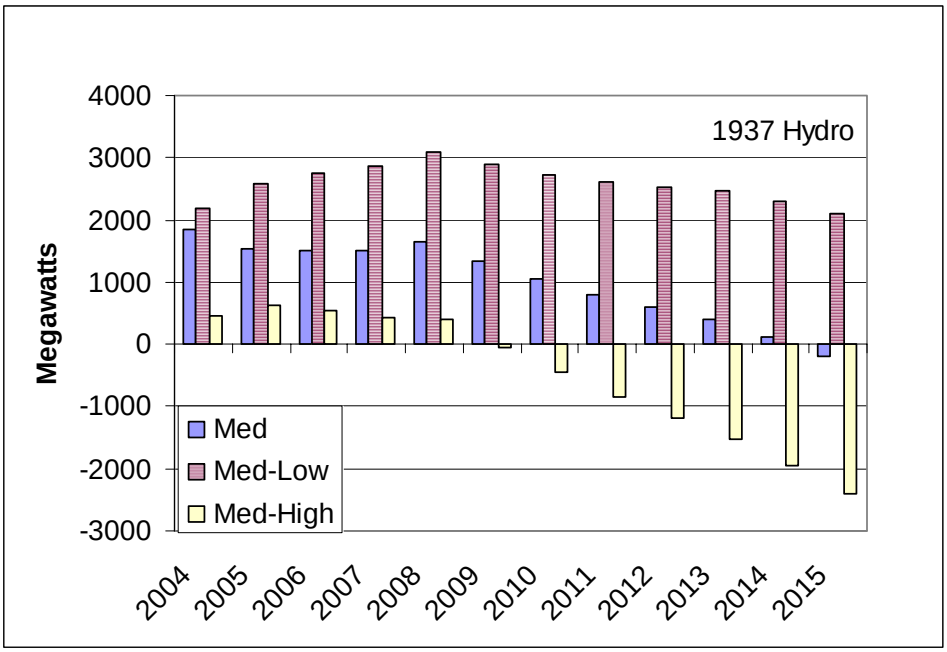

Figure 2-6: Load Resource Balance with Existing Resources Under Medium-Low, Medium And Medium-High Demand Forecasts

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 2-7 shows recent monthly natural gas spot market prices at the national and regional level. National wellhead prices from 2000 to 2003 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.

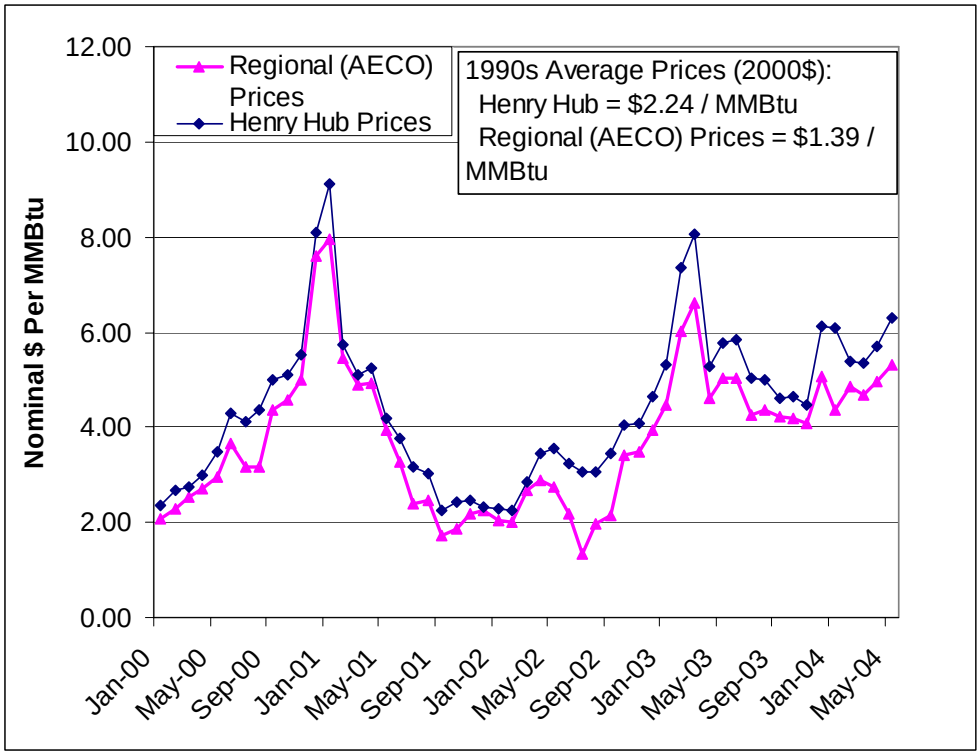

Figure 2-7: Recent National and Regional Natural Gas Prices

The Council forecasts a range of natural gas prices for use in this draft plan. The forecast reflects the assumption that future natural gas prices will be significantly higher than the 1986 to 2000 period. The medium case assumes that national wellhead natural gas prices will average about $5.45 in 2004 (2000$) and decrease to $4.00 by 2010. Prices are then assumed to further decrease gradually to $3.80 by 2015 and then grow back to $4.00 by 2025. The ending prices in 2025 vary from $3.00 in the low to $5.10 in the high. The forecasts and historical prices are shown in Figure 2-8.

The Council does not expect fuel prices to follow the smooth trends shown in Figure 2-8. 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 and, on average, higher, 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, through the portfolio model simulations.

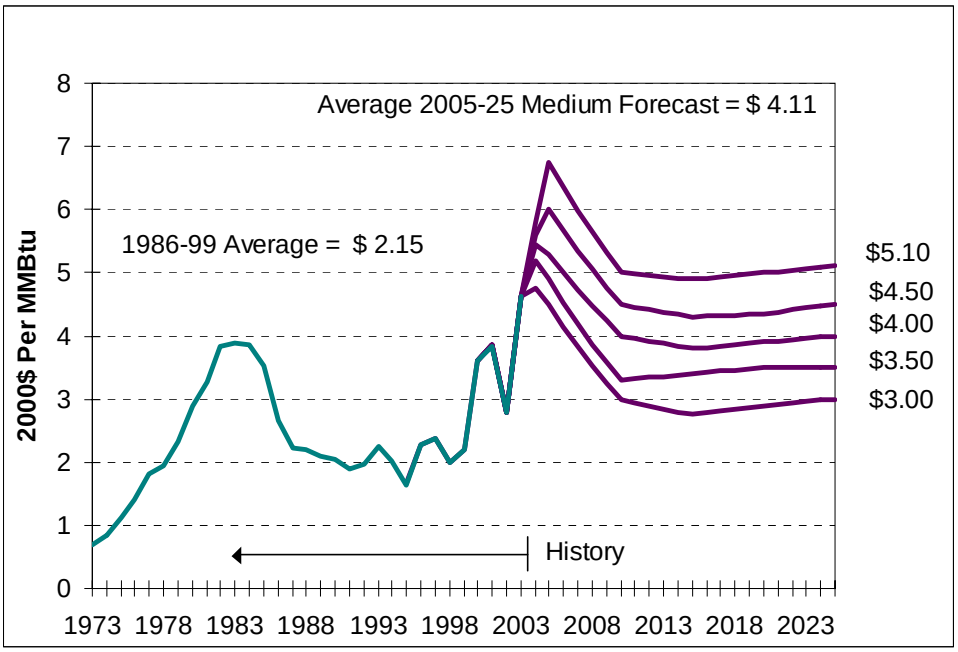

Figure 2-8: Range of Future Natural Gas Price Forecasts

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 generally reflects 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. In the low and medium-low cases, coal is projected to decline slightly relative to general inflation although at a much slower rate than in the past. Small increases are assumed in the medium and medium-high cases. 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 B. Assumptions regarding electricity generating technology using these fuel sources are described in Chapter 5 and Appendices I and J.

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. Conservation analysis and assumptions are described in Chapter 3 and Appendices D through G.

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 by 2000 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, improved building codes and appliance efficiency standards. As noted above, the region succeeded in acquiring 1,800 megawatts of conservation by 2000 and has acquired additional conservation since.[6] However, the region did not capture all the conservation identified in that first power plan or in subsequent plans.

Do past achievements mean there is much less 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 2,700 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.

[6] The match of conservation achievement does not mean that the region's conservation programs followed the Council's recommendations. Rather, acquisitions of some conservation measures fell below the Council's recommendations, but these shortfalls were roughly balanced by acquisitions of efficiency in the form of newly-developed technology, technology not available or included in the Plan in 1983. If conservation programs had reached all of the 1983 Council recommendations the total acquisitions of cost-effective conservation by 2003 should have been significantly above 2500 MW.

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 timeliest 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. Demand response is discussed in Chapter 4 and Appendix H.

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 smaller-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. Renewable resources and other generating technologies are described in Chapter 5 and Appendices I and J.

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 2-9 shows average monthly prices during 2003, which averaged $37 per megawatt-hour.

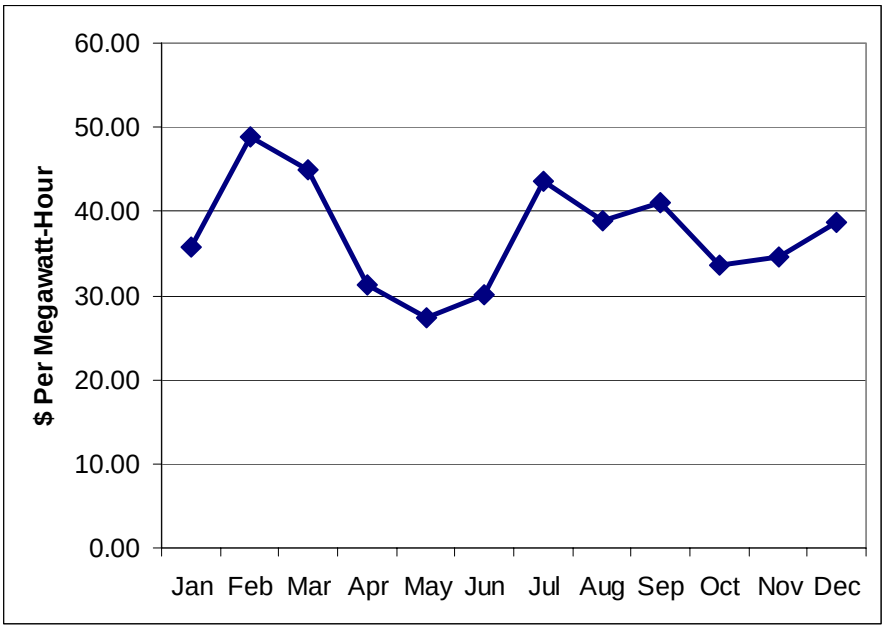

Figure 2-9: Wholesale Spot Market Electricity Prices at Mid-Columbia Pricing Point: Jan. - Dec. 2003

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 basis for estimating the cost of purchasing from, or selling into, the wholesale electricity market in the Council's risk analysis.

As in the case of electricity demand and natural gas price forecasts, the electricity price forecast described in this section forms only the central tendency of future electricity prices that are assessed in the portfolio model. Electricity price volatility is a key issue addressed in this plan. The portfolio model reflects significant variations in electricity prices seasonally, regionally, and in response to a number of varying conditions. These conditions include hydro conditions, natural gas prices, demand variations, load-resource balance, transmission congestion, and a significant random element reflecting the effects of events in the rest of the western interconnection. This is discussed further in Chapter 6 on risk assessment and management.

The AURORA® Electric Market Model is used to estimate Western electricity prices on an hourly basis.[7] 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 Figure 2-12. 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 market price 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. 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 AURORA® model forecast is based on electricity generation choices and dispatch that make economic sense given a forecast of demand growth and expected costs of constructing and operating alternative generation technologies, including expected fuel costs. The AURORA® forecast of future resource development differs from the Council's portfolio analysis in that it does not evaluate the effects of uncertainty and volatility in the key determinants of electricity price. AURORA, however, more explicitly models the hour-by-hour operation of the electricity supply system and the overall interconnected western grid. For these reasons, the future resource mix of the electricity price forecast differs somewhat from the Council's resource development recommendations. The forecast of market electricity prices is described in detail in Appendix C.

The levelized annual average electricity price at the Mid-Columbia trading hub for 2005 through 2025 is forecast to be $36.20 per megawatt-hour (2000$). Figure 2-10 shows forecasted annual average prices for the Mid-Columbia trading hub. Prices decline between 2005 and 2010 reflecting declining natural gas prices. Prices increase gradually through the remainder of the planning period as slowly increasing natural gas prices are partially offset by improved combined-cycle efficiency and increasingly more cost-effective windpower. Because mean values of hydropower, fuel prices and other potentially volatile underlying assumptions are used in this forecast, possible episodes of price excursions resulting from volatility in the gas market or poor hydro conditions are not shown. Volatility is addressed in the portfolio model analysis.

[7] 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.

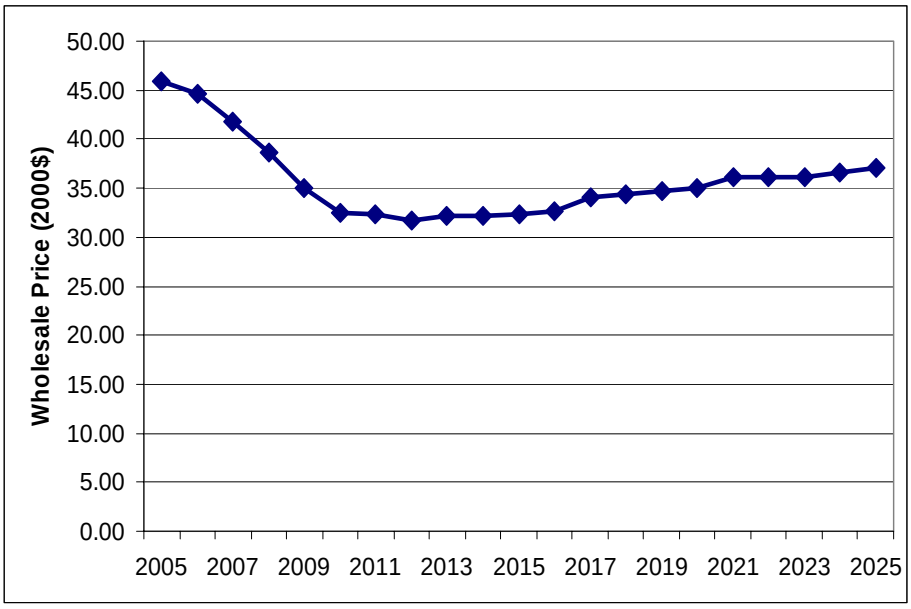

Figure 2-10: Forecast of Average Annual Wholesale Power Prices at the Mid-Columbia Trading Hub

The Council did sensitivity tests to determine how changes in assumptions or policies would affect the model's price forecasts. Prices were shown to increase in response to aggressive CO_2 control, higher reserve margin requirements and higher natural gas prices. Prices decreased in response to low natural gas prices, less aggressive CO_2 policy, and reduced electricity demand. These changes also affected the role of renewables, coal and natural gas-fired generation. The effects of these uncertainties are described in Appendix C.

The annual average prices of Figure 2-10 conceal significant seasonal and daily price variation. Seasonal variations are revealed in Figure 2-11 illustrating monthly average prices. Also shown in Figure 2-11 is the effect of southwestern load patterns on Northwest market prices. Northwest market prices track those in the Southwest whenever transfer capacity is available on the Pacific interties. 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 C.

The forecast WECC resource mix associated with the electricity price forecast is shown in Figure 2-12. 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. Over the period 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 42,000 megawatts of combined-cycle plant, 29,000 megawatts of coal capacity, 30 percent of which is gasified coal generation, 23,000 megawatts of wind capacity and 3,300 megawatts of gas peaking capacity. Not shown in Figure 2-12 is about 9,000 megawatts of short-term demand response capability assumed to be secured by 2025.

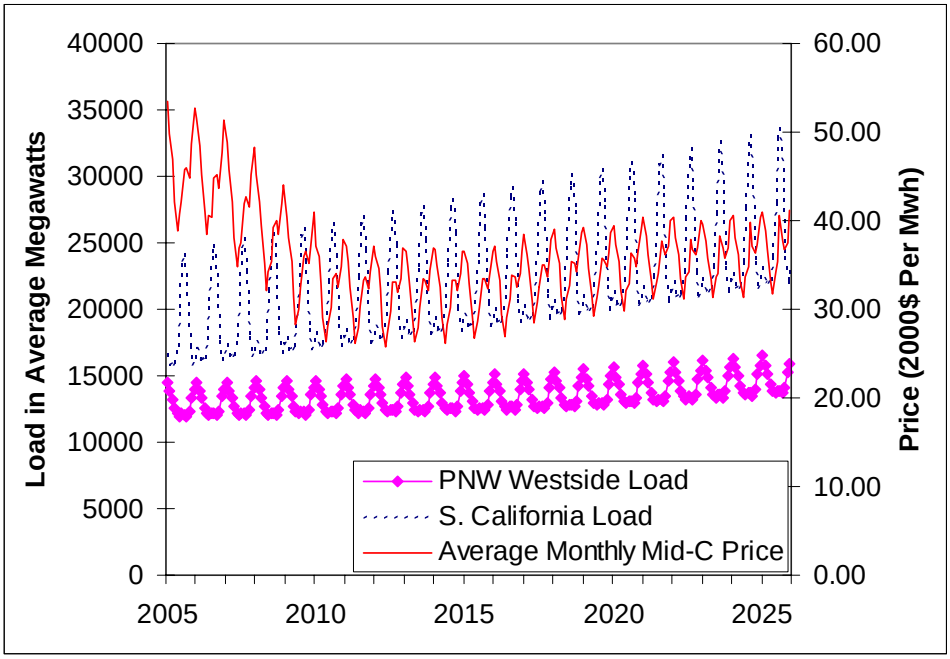

Figure 2-11: Forecast Monthly Wholesale Mid-Columbia Electricity Prices Compared to Northwest and Southwest Loads

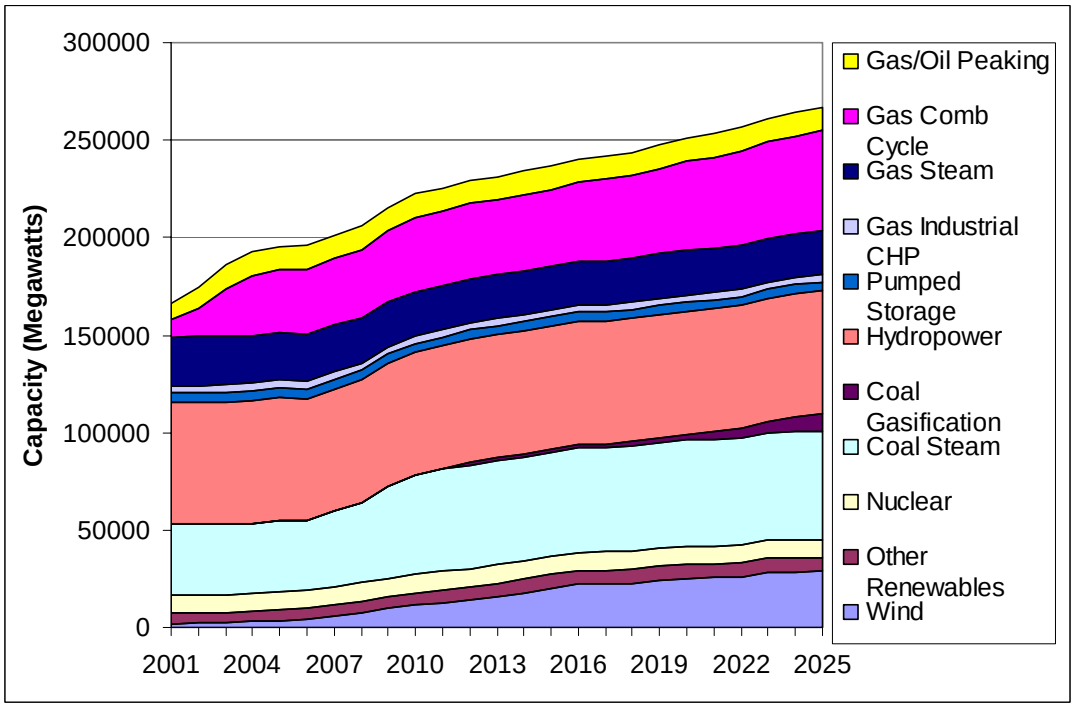

Figure 2-12: Base Case Forecast WECC Resource Mix

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.

The power plan contains actions that are intended to help the region make progress in resolving these policy problems.

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 Fifth 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 lose 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 the 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 capability 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.

Conservation Resources

OVERVIEW

This chapter provides an overview of the procedures and major assumptions used to derive the Council's estimates of conservation resources available in both the public and private utility service territories across the region. It describes the cost and availability and other key characteristics of the conservation potential. It also describes the Council's policy on conversion from electricity to natural gas as an electric efficiency measure.

In the Council's power plan, conservation is defined as the more efficient use of electricity. This means that less electricity is used to produce a given service at a given amenity level. Conservation resources are measures that ensure the efficient use of electricity for new and existing residential buildings, household appliances, new and existing commercial buildings, commercial-sector appliances, commercial infrastructure and industrial and irrigation processes. For example, buildings in which heat loss is reduced through insulating and air tightening require less electricity for heating. These conservation efficiencies mean that less electricity needs to be generated, saving operating costs and ultimately requiring less new power plant construction. Conservation also includes measures to reduce electrical losses in the region's generation, transmission and distribution system.

Conservation has been a central ingredient in the resource portfolios of previous plans for meeting future electrical energy needs. Each kilowatt-hour of electricity conserved means that one less kilowatt-hour needs to be generated. But conservation resources carry costs and risks, as do generation and demand response resources available to the region for development. The Council's uses a portfolio model to determine what resources to develop on what schedule in order to minimize power system costs and risks. (See Chapters 6 and 7 for a discussion of the portfolio analysis) Each of the resources considered by the portfolio model, including conservation, carry unique physical and financial characteristics that determine its value and risk to the system. The amounts of cost-effective conservation identified in this chapter are not presented as targets, but rather a summary of conservation resource characteristics. How much of this conservation resource to develop, at what pace, and under which development decision criteria is determined in the portfolio analysis. In the portfolio analysis, the costs and risks of developing conservation are evaluated relative to other resource alternatives considered in this plan. That analysis, presented in Chapter 7, leads to action plan targets for conservation acquisition.

In order for the portfolio model to identify how much conservation is appropriate to develop, the Council first estimates the amount, cost, and availability of conservation. The cost, amount and characteristics of the supply of conservation resources available to the region are described and reported in this chapter under specific medium-case assumptions. The amount of conservation available to develop depends on future growth patterns, economic cycles, and success of conservation programs, timing of codes and standards, power prices and a host of other factors. For example, more conservation would be available if the region grows at a faster pace than the medium-demand forecast. Less if the regions grows more slowly. Similarly, more would be

cost-effective than reported in this chapter, if power prices are higher than the medium forecast used as a proxy for cost-effectiveness in this chapter.

This draft plan identifies over 4,600 average megawatts of technically available conservation potential in the medium-demand forecast by the end of the forecast period. About half of the potential is from lost-opportunity measures, which must be captured at the time new buildings are built or new appliances and equipment is purchased. The other half is discretionary with regard to timing. Discretionary conservation can be deployed any time within practical limits.

But not all of those 4,600 average megawatts of conservation potential are practicably achievable or economic to deploy. The Council's conservation resource assessment takes into account both the fraction of technical potential estimated to be ultimately achievable and the fraction estimated to be cost-effective under medium case assumptions.

The technically available conservation potential identified by the Council is reduced to reflect that a fraction of measures that can never be practicably achieved, even if the measures are free and cost-effective. Some customers will not adopt some measures, some equipment will not be replaced with more efficient equipment for a variety of reasons, and some new buildings and equipment will not meet energy codes and standards. To account for this, the Council estimates the fraction of the conservation potential is practicably achievable over the course of the twenty-year plan period and the pace at which the conservation programs can be accelerated or codes and standards adopted. The Council believes that program penetration can reach 85 percent over twenty years. But, early-year penetration rates for new programs will be lower because it takes time to ramp up programs. Specific ramp-up constraints, and year-to-year acceleration limits used in the portfolio analysis are described in Chapter 7. For the purpose of illustrating conservation potential in this chapter, the Council assumes 85 percent or 3,900 average megawatts, of the estimated 4,600 average megawatts of cost-effective conservation is achievable over the course of the twenty-year planning period.

Some of the conservation identified in the Council's resource assessment is relatively expensive. The portion of the 3,900 average megawatts of achievable conservation potential that will be cost-effective to develop depends on how future market prices unfold, how valuable the conservation resource is compared to other resources and the relative risk of conservation compared to other resources. The Council's portfolio analysis is used to determine best conservation development strategies given the uncertainties the region faces. But, for illustrative purposes in this chapter the Council reports amounts estimated to be cost-effective based on a medium-case forecast of power market prices at the Mid-Columbia trading hub for every hour over the next twenty years. Using this estimate of future wholesale electricity prices, about 2,800 average megawatts of the 3,900 achievable megawatts would be cost-effective.

These estimates for the fraction achievable and fraction that would be cost effective produce a single point estimate of 2,800 average megawatts of cost-effective and achievable conservation available to the region by 2025. This achievable and likely cost-effective conservation potential is available at an average levelized cost of about 2.4 cents per kilowatt-hour.[1] This is equivalent

[1] The energy savings potential and average cost estimates in this chapter include administrative costs and adjustments for transmission and distribution line losses. Levelized cost calculations are performed in constant (2000$) using a discount rate of 4 percent over a financing period of 15 years.

to the capability of more than eight new 400 megawatts coal-fired power plants at about two-thirds of the cost.[2]

Table 3-1, and Figure 3-1 show the distribution and estimated benefit cost ratios of the region's achievable and cost-effective conservation potential by major end-use and sector under the Council's medium forecasts of load growth, power and fuel prices, hydro conditions and resource development. Figure 3-2 shows the conservation supply curve by sector for all conservation identified in this assessment. Costs reported are the levelized costs of the conservation measures and expected program costs in (2000$).[3] Reported savings include reduced line losses.

[2] Based on a 400 megawatts coal-fired power plant seeing service in 2009. Under average conditions, such a plant would operate at an average capacity of 326 megawatts with a levelized cost of $36.68 per megawatt hour (year $2,000).

[3] These costs are not total resource costs. They do not include the value of deferred transmission or distribution system savings, quantifiable non-energy benefits, or operational and maintenance savings attributable to conservation measures. Total resource cost includes the net costs of conservation resources. The Council uses total resource costs, which are measure and program costs net of associated benefits when evaluating the relative costs of conservation and generating options to assure the fair comparison of conservation and generating resources.

Table 3-1: Achievable and Cost-Effective Conservation Potential

Sector and End-Use	Cost-Effective Savings Potential (MWa in 2025)[4]	Average Levelized Cost (Cents/kWh)[5]	Benefit/Cost Ratio[6]
Commercial New & Replacement Lighting	245	1.2	9.1
Agriculture - Irrigation	80	1.6	3.2
New & Replacement AC/DC Power Converters[7]	156	1.5	2.7
Residential Clothes Washers	135	5.2	2.6
Residential Dishwashers	10	1.6	2.6
Commercial New & Replacement Infrastructure[8]	11	1.4	2.4
Residential Compact Fluorescent Lights	535	1.7	2.3
Residential Water Heaters	80	2.2	2.3
Commercial Retrofit Lighting	114	1.8	2.2
Residential Refrigerators	5	2.1	2.2
Commercial Retrofit Equipment[9]	109	3.4	2.1
Residential HVAC System Conversions	70	4.3	2.1
Commercial New & Replacement Shell	13	1.6	2.0
Industrial Non-Aluminum	350	1.7	2.0
Residential New Space Conditioning - Shell	40	2.5	2.0
Residential Existing Space Conditioning - Shell	95	2.6	1.9
Residential HVAC System Commissioning	20	3.1	1.9
Commercial Retrofit Infrastructure[8]	105	2.2	1.8
Commercial New & Replacement Equipment[9]	84	2.2	1.8
Commercial New & Replacement HVAC	148	3.0	1.5
Commercial Retrofit HVAC	117	3.4	1.3
Commercial Retrofit Shell	9	2.9	1.3
Residential HVAC System Efficiency Upgrades	65	2.9	1.2
Residential Heat Pump Water Heaters	195	4.3	1.1
Residential Hot Water Heat Recovery	25	4.4	1.1
Total	**2,814**	**2.4**	**2.7**

[4] This is the total amount of conservation estimated to be cost-effective and achievable, given sufficient economic and political resources, over a 20-year period under the medium forecast of loads, fuel prices, water conditions, and resource development.

[5] These levelized costs do not include the 10-percent credit given to conservation in the Northwest Power Act.

[6] These "benefit-to-cost" (B/C) ratios are derived by dividing the present value benefits of each measure's energy, capacity, transmission and distribution and non-energy cost savings by the incremental present value cost (including program administration) of installing the measure.

[7] Measure occurs in residential, commercial and industrial sectors.

[8] Commercial infrastructure includes sewage treatment, municipal water supply, LED traffic lights, and LED exit signs.

[9] Commercial equipment includes refrigeration equipment and controls, computer and office equipment controls and laboratory fume hoods.

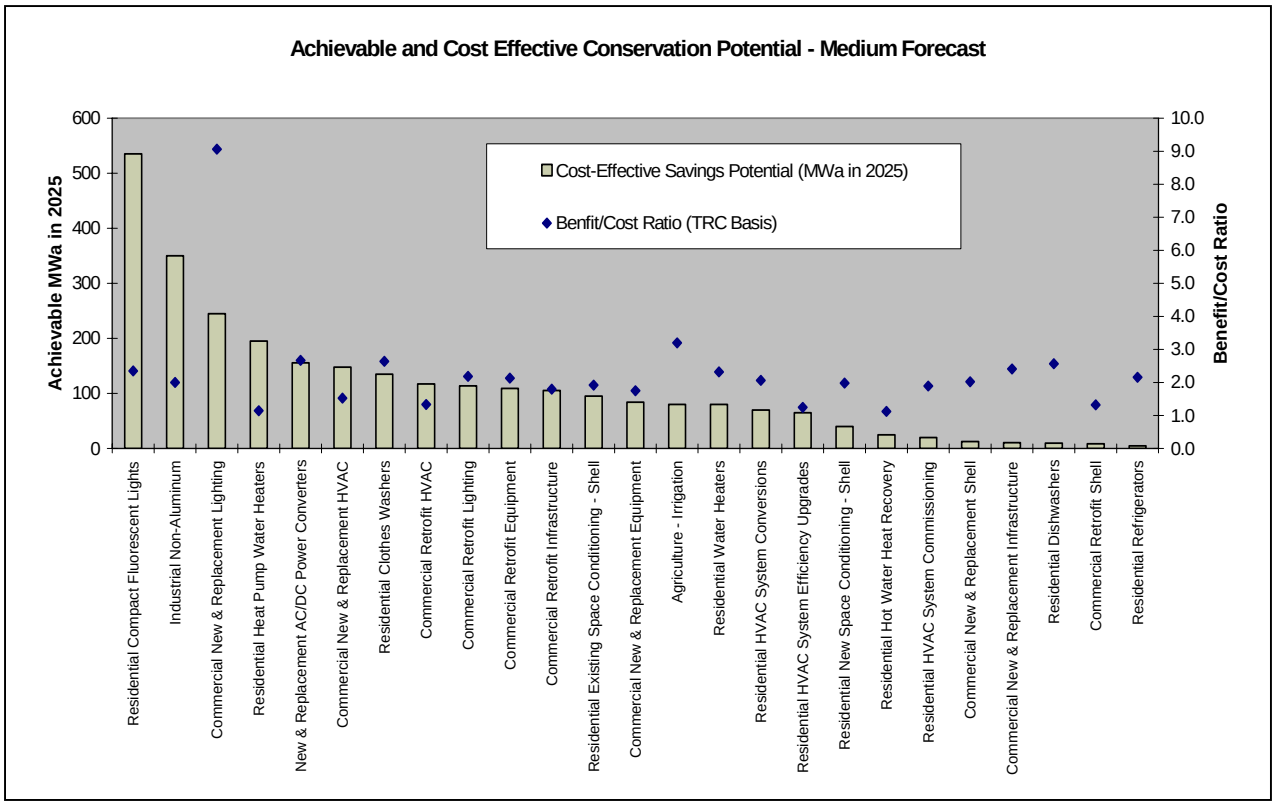

Figure 3-1: Achievable and Cost-Effective Conservation Potential

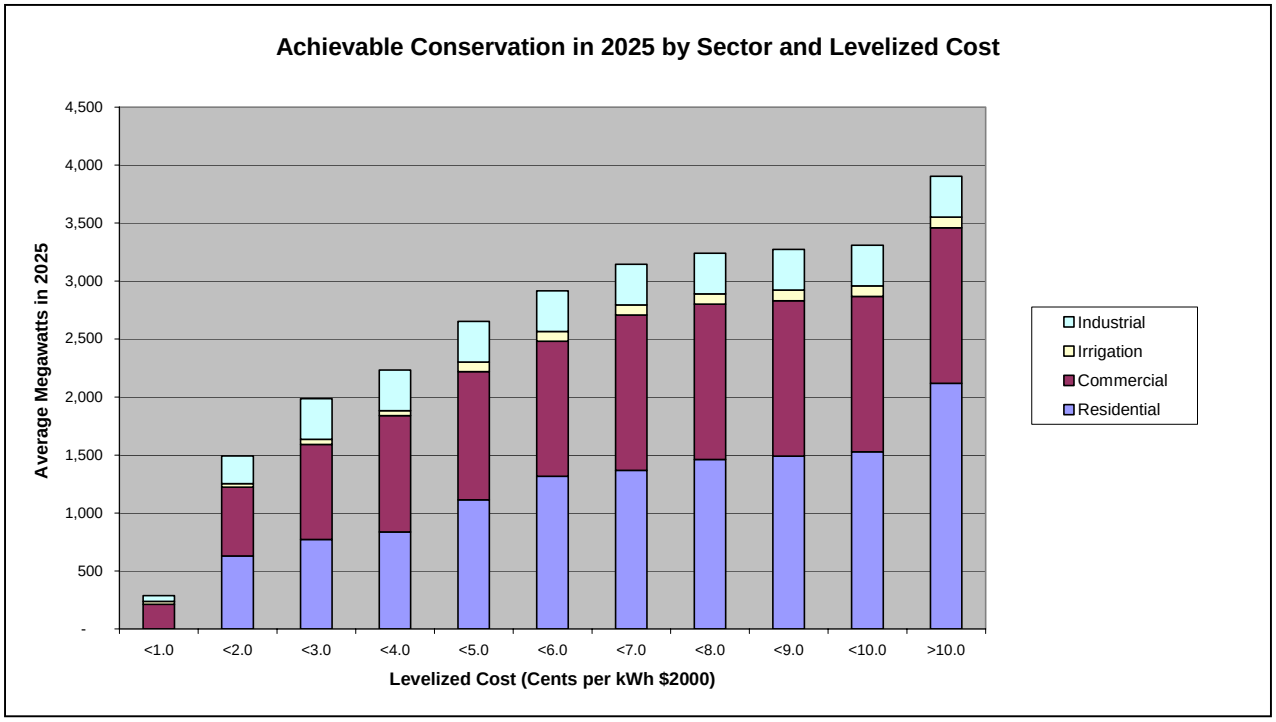

Figure 3-2: Achievable Conservation in 2025 by Sector and Levelized Cost

TWO DECADES OF CONSERVATION PROGRESS

Since the adoption of the Council's first power plan in 1983 the region has made significant progress in acquiring conservation. The Council's first power plan stated that the acquisition of cost-effective conservation should be used to reduce year 2002 loads by 5 to 17 percent depending upon the rate of economic growth experienced in the region. The plan called upon Bonneville and region's utilities to develop and implement a wide array of conservation programs. The plan also called upon the state and local governments to adopt more energy efficient building codes. It called upon the federal government to adopt national energy efficiency standards for appliances and to upgrade its existing efficiency standards for new manufactured homes.

In response to the Council's first power plan, the Bonneville Power Administration and the region's utilities initiated conservation programs across all economic sectors. Between 1980 and 2002, these programs acquired over an estimated 1,425 average megawatts of electricity savings. Since its formation in 1996, Bonneville and the region's utilities have sponsored the market transformation initiatives of the Northwest Energy Efficiency Alliance. Alliance programs have contributed another 110 average megawatts of savings, increasing the 1980-2002 regional total to 1,535 average megawatts. The average levelized cost of these savings to the region's power system was approximately 2.1 cents per kilowatt-hour (2000$), or approximately 60 percent of the expected cost of electricity from new generating resources. However, the region did not capture all the conservation identified in that first power plan. Nor has it captured all the cost-effective conservation identified in subsequent plans.

While progress toward adoption of more energy-efficient energy codes has proceeded at a slower pace, all of the Northwest states have now adopted energy codes that require new residential and commercial buildings and those buildings that undergo major renovations or remodeling to be constructed with significantly more efficiency measures. By 2002 buildings constructed to these codes were saving an estimated 475 average megawatts of electricity. The region will continue to accrue additional savings as future buildings are constructed in accordance with these codes.

At the federal level, new standards for residential water heaters and appliances such as refrigerators, freezers and clothes washers were first adopted in 1987. In 1992 Congress enacted federal standards for additional appliances, electric motors, certain commercial heating, ventilating, air conditioning equipment and lighting equipment. After much debate, in 1994 the Department of Housing and Urban Development (HUD) revised its federally pre-emptive energy efficiency standards for new manufactured homes for the first time in 20 years. Taken together these federal efficiency standards saved an estimated 450 average megawatts of electricity in 2002.

Figure 3-3 shows that cumulative conservation savings from Bonneville and utility programs, as well as state codes and federal standards from 1980 through 2002 total about 2,500 average megawatts. By 2002 the 2,500 average megawatts of conservation resources developed in the region were meeting between 10-12 percent of Northwest electric energy service needs. To place this in perspective, this is more electricity than was consumed in the entire state of Idaho during 2002.

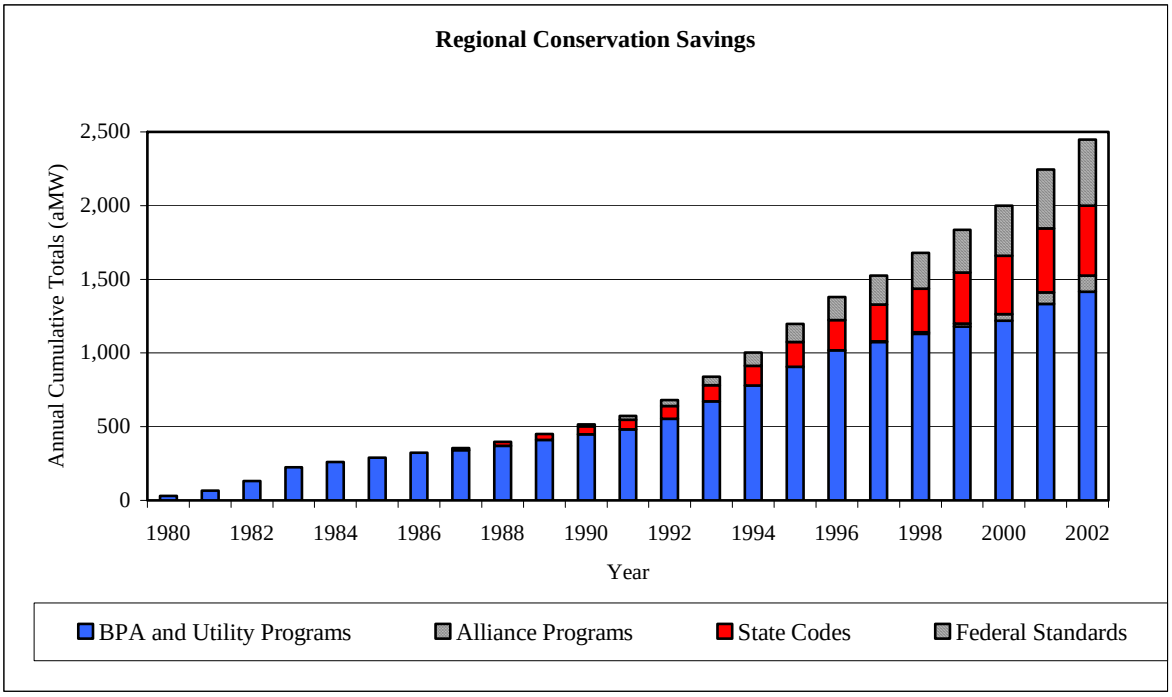

Figure 3-3: Regional Conservation Savings 1980 - 2002

MAJOR CHANGES IN CONSERVATION RESOURCE ESTIMATES

The Fourth Power Plan's conservation estimates were prepared in 1995. This new estimate of energy conservation potential takes into account significant changes that took place in the intervening years. These include: 1) conservation acquired since the Fourth Power Plan; 2) changes in avoided costs; 3) technology improvements; and 4) changes in baseline characteristics forecasts. Each of these changes is discussed in the following sections.

Conservation Acquisition Since the Adoption of the Fourth Power Plan

Since 1995 utility conservation programs, including regional market transformation activities, changes in federal and state codes and standards, have captured some of the cost-effective conservation potential identified for development in that plan.[10] Bonneville and utility programs acquired approximately 620 average megawatts of conservation resources between 1996 and 2002. In addition, the Northwest Energy Efficiency Alliance and its regional utility partners are increasing the market share of a wide array of higher-efficiency appliances, building practices, residential lighting and other measures. Figure 3-4 shows that by the year 2025 the Council estimates approximately 170 average megawatts of conservation will be captured by these existing market transformation efforts.

[10] Market transformation means efforts to improve the market viability and availability of specific conservation equipment or services so that they can achieve high levels of market penetration with little or no utility incentives. Because these markets typically cut across multiple utility service territories, market transformation efforts in the Northwest have been developed in conjunction with the region's utilities through the Northwest Energy Efficiency Alliance (NEEA).

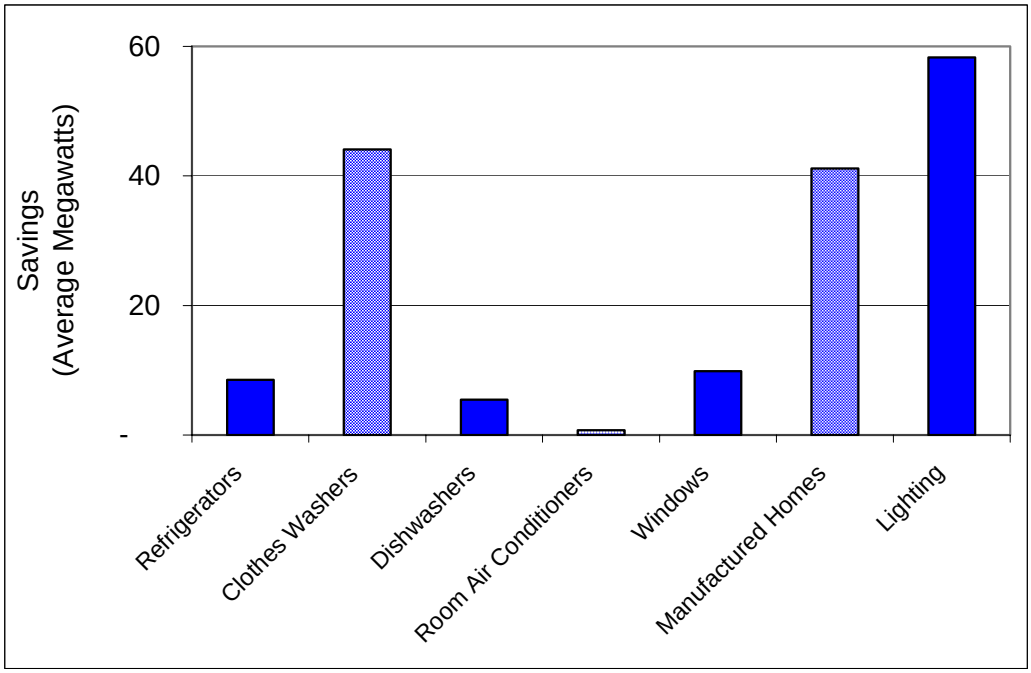

Figure 3-4: Future Load Reductions From Existing Market Transformation Efforts

Since 1995, revised federal standards for refrigerators, clothes washers, electric water heaters, heat pumps and central and room air conditioners have been adopted. Table 3-2 shows the magnitude of the improvement in efficiency required by these standards and their effective dates. Figure 3-5 shows the amount of savings attributable to each of these standards under the Council's medium load growth forecast. In aggregate, these standards are expected to save the region 730 average megawatts before the year 2025.

Table 3-2: Efficiency Improvements Required by Federal Appliance Efficiency Standards

COVERED APPLIANCE/EQUIPMENT	IMPROVEMENT OVER EXISTING STANDARD	EFFECTIVE DATE
Room Air Conditioners	10 - 25% depending on size	October 1, 2000
Refrigerators/Freezers	25 - 30%	July 1, 2001
Clothes Washers	20% 35%	January 1, 2004 January 1, 2007
Water Heaters	5%	January 20, 2004
Central Air Conditioners and Heat Pumps	30% for cooling 15% for heating	January 23, 2006

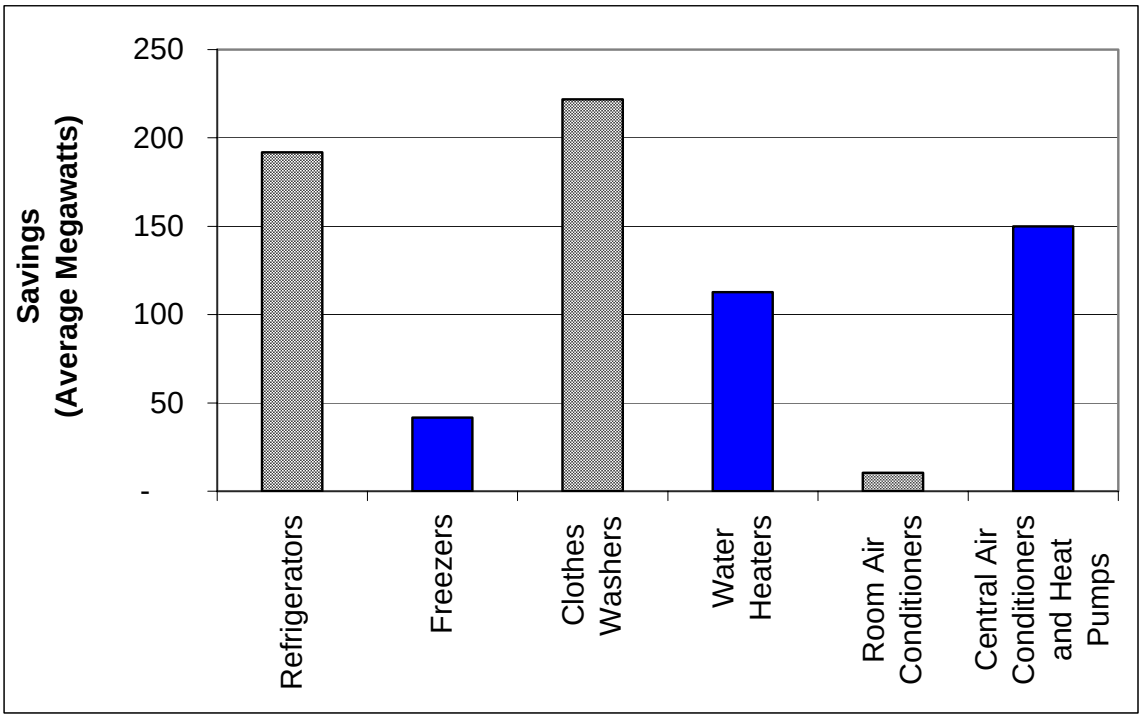

Figure 3-5: Forecast Regional Savings from Recently Revised Federal Appliance Efficiency Standards in 2025

In addition, Oregon, Washington, Seattle and Idaho have improved or adopted energy efficiency codes for commercial buildings since 1995. Oregon completed significant revisions, which took effect starting in 2003. Washington adopted modifications in 2001 and 2002. Seattle upgraded the its energy code in 2002. And Idaho adopted its first commercial building code, which took effect in 2003. The Council estimates that these changes, adopted since 1995, will reduce energy use in commercial buildings by about 100 average megawatts in 2025 under the medium growth forecast.

These forecast and historic savings have been incorporated into the Council's load forecast and removed from its conservation resource supply estimates. The 620 average megawatts of utility-acquired conservation secured from existing buildings, appliances and equipment reduces the remaining conservation potential from those applications. This is accounted for by a combination of reducing the remaining number of buildings or homes that are available for efficiency upgrades and reducing the level of savings in each. The efficiency gains from market transformation and codes and standards described earlier not only directly reduce the remaining potential but also reduce future expected load growth by an equivalent amount. This is accounted for by reducing the pace of expected load growth and by increasing the "baseline" efficiency used for the building, appliance or equipment affected by these codes and standards.

Changes in Avoided Costs

A second factor that has altered the amount of conservation remaining to be captured is the expected cost of new power supplies. In the Council's Fourth Power Plan, conservation resources with a real levelized cost of between 2.4 and 3.1 cents (2000$) per kilowatt-hour were considered regionally cost-effective. The "cost-effectiveness limit" used in this analysis is

between 3.3 and 8.9 cents (2000$) per kilowatt-hour for a measure with a 20-year resource life, depending upon the daily and seasonal distribution of the savings.[11] Table 3-3 shows that under the Council's medium forecast, had the region's avoided cost of new generation remained under 3.0 cents per kilowatt-hour, approximately 765 average megawatts of conservation potential would not have been cost-effective.

Table 3-3: Changes To Conservation Resource Potential Due To Higher Avoided Cost

Sector & End Use	**Average Megawatts**
Residential Clothes Washers	135
Heat Pump Water Heaters	195
Hot Water Heat Recovery	35
Residential HVAC System Conversions	60
Residential HVAC System Commissioning & Repair	20
Commercial Lighting and HVAC Measures	270
Irrigated Agriculture	50
Total	**765**

Technology Improvements

Technological improvements since the adoption of the Fourth Power Plan have added cost-effective savings potential where none existed. Significant increases in the efficiency and/or reduction in the cost of more efficient refrigerators and freezers, clothes washers, dishwashers, lighting and windows have taken place over the past few years. The following two examples illustrate the significance of these changes.

The "most-efficient" clothes washers now available are 50 percent more efficient than the recently revised federal standard that is not scheduled to take effect until 2007. As a result, there are now 290 average megawatts of conservation potential available from the use of these more efficient clothes washers -- above and beyond a federal standard that will not take effect for three more years.

The average cost of compact fluorescent lamps (CFLs) assumed in the Fourth Power Plan was $12.55 per lamp. Today, CFLs can now be purchased for less than $3.00 per lamp. Moreover, current CFLs are significantly smaller in size and now include multiple output ("3-way") lamps, flood and spot lights and dimmable ballasts; thus they can now be used in nearly all residential lighting fixtures and applications. Due to their cost and physical characteristics, the Fourth Power Plan assumed that only three CFLs could be installed in the average residence. This draft plan assumes that nearly all fixtures with "screw in" incandescent lamps can be replaced with CFLs by 2025, increasing conservation potential from this one technology from 60 average megawatts to nearly 600 average megawatts.

[11] In this draft plan, the Council differentiates the marginal cost of supplying new power based on the time of day, the day of the week and the month of the year. As a result, the "cost-effectiveness" of a particular conservation measure depends on when it produces savings. See Appendix E: Conservation Cost-Effectiveness Methodology for further explanation.

Regional market transformation initiatives have produced results that justify including some new measures in the region's conservation portfolio. For example both developing the infrastructure to perform residential duct testing and sealing and developing lower-cost methods of reducing sewage treatment energy use are new measures in the assessment that sprang from regional market transformation efforts. Also in the "non-buildings" category, several new technologies have added to the stock of cost-effective conservation opportunities. These include better control of the power use of desktop computers, higher-efficiency commercial refrigerators, freezers and ice makers, LED traffic signals and exit signs and more efficient AC-to-DC power transformers used in hundreds of appliances from cell phone chargers to televisions. These new technologies have added nearly 1,300 average megawatts of conservation potential that was not considered or available in 1995.

The factors affecting the regional conservation potential estimates and their contributions are summarized in Table 3-4.

Table 3-4: Summary of Major Changes Affecting Regional Conservation Potential

Factor	**Affect on Conservation Potential in Medium Forecast (Average Megawatts)[12]**	
	Decrease	**Increase**
Utility Program Acquisitions	600	0
Regional Market Transformation Actions	170	0
New/Revised Federal Standards	730	0
Higher Avoided Cost	0	767
Technology Improvements	0	1240

Changes in the Load Forecast

In addition to these factors, changes in the load forecast can result in major changes in conservation resource potential. Five factors exerting the most influence are 1) the number of new residences heated with electricity; 2) the market share of electric water heating; 3) the electric heat saturation in commercial buildings; 4) the commercial building demolition rate; and 5) the rate of non-aluminum industrial load growth. Table 3-5 compares these factors for the draft Fifth Power Plan's medium forecast with the medium forecast from the Fourth Power Plan.

Table 3-5 shows that the most significant changes in the Council's estimate of regionally cost-effective conservation were due to differences in the underlying load forecast in the commercial and industrial sectors. Due to lower (relative to electricity) gas prices, more commercial buildings are expected to use natural gas heat. This lowered the commercial sector conservation potential. The Council also forecast fewer electrically heated dwellings and fewer electric water heaters by 2025. This also reduces the potential for conservation in the residential sector.

[12] Utility program acquisitions decrease the conservation resource potential available in existing buildings and equipment; the revised codes and standards impact conservation potential in new construction and lower avoided cost; and technology improvements affect both new and existing electricity applications.

The industrial sector growth is significantly lower than that in the Fourth Power Plan. DSI loads in 2025 are forecast to be 1,681 average megawatts lower than in the Fourth Power Plan. Under the medium forecast, non-DSI industrial loads are forecast to be 1,375 average megawatts lower. The Fourth Power Plan did not contain an estimate for conservation potential in the DSIs, so the reduction in future load from these industries had no impact on the regional conservation potential. On the other hand, the reduction in future non-DSI industrial loads has reduced the conservation potential in this sector.

The lower forecast for industrial electricity use is a result of anticipated changes in the region's industrial mix. As Northwest electricity retail prices approach those experienced in other regions of the nation electricity-intensive industries such as pulp and paper and food processing are anticipated to comprise a smaller portion of the overall industrial sector load. This has reduced the total conservation potential available from non-DSI industrial loads.

Table 3-5: Major Changes in Medium Load Forecast Affecting Conservation Potential

Factor	Fourth Power Plan Value	Draft Fifth Plan Value	Impact on Conservation Potential
New Electrically Heated Dwellings	1.18 million	.813 million	Decrease Potential
Residential Water Heating Saturation	78%	64%	Decrease Potential
Commercial Sector Electric Heating	55% to 40% (over 20 years)	33% to 30% (over 20 years)	Decrease Potential
Commercial Sector Demolition Rate	High	Low	Decrease Potential
Non-Aluminum Industrial Load in 2015	7152 MWa	5919 MWa	Decrease Potential

ESTIMATING THE CONSERVATION RESOURCE

The following section summarizes the Council's estimates of conservation resources available to the region. The narrative is based on calculations from the Council's medium demand forecast. Conservation resources under these medium case conditions are summarized for each sector.

The evaluation of conservation resources involves four major steps. The steps are: 1) develop estimates of technical potential; 2) identify the amount of achievable and the cost of conservation including its contribution to energy and capacity needs, 3) identify development characteristics of the cost-effective conservation potential including programmatic approaches and timing constraints; and 4) identify conservation development strategies that optimize the value of conservation for the region based on its cost, savings, dispatchability and risk-minimization characteristics. These steps are described briefly in the sections below. Methods used in the second step, identifying the amount of cost-effective potential, are explained in further detail in Appendix D. While these methods are not significantly different than in the last plan, their application under new avoided costs leads to a significant increase in conservation potential and changes in the values of different conservation measures.

Step 1: Develop estimates of Technical Potential

The first step is to develop conservation supply curves based on engineering analysis. This step entails evaluating the leveled life-cycle cost of all conservation measures, determining what fraction of forecast building, appliance or equipment stock the measures apply to, whether the measure is a lost-opportunity, and savings interactions from application of multiple measures. Measure costs include capital, financing, operating and period replacement costs. Measure energy and capacity savings are estimated, including the monthly and daily shape of the savings. Non-energy benefits and costs, such as water savings or changes in natural gas use associated with of each measure are estimated to the extent they can be identified and calculated. This results in a summary of all the costs and savings for technically feasible measures. From these estimates the Council calculates several key parameters including levelized life-cycle cost and benefit-cost ratios.[13]

This technical conservation supply curve represents all the available conservation potential and its associated costs. However, it is not all practically achievable. "Achievable conservation," is defined as the net energy savings the Council anticipates after taking into account factors such as consumer resistance, quality control and unforeseen technical problems. Historically, the Council has assumed that 85 percent of the technically available conservation was achievable because it believed that the wide assortment of incentives and regulatory measures provided by the Northwest Power Act could persuade the region's electricity consumers to install a large percentage of the available and cost-effective conservation. The draft Fifth Power Plan continues to assume that 85 percent of the cost-effective conservation can be achieved.

Two supply curves are passed to the Council's portfolio analysis model. One curve is for discretionary conservation measures. The other describes lost-opportunity conservation measures. The Council's portfolio model then evaluates conservation and other resources available to meet the region's power needs and identifies resource development strategies for each. The achievable conservation supply curves made available to the portfolio analysis model includes some measures that are cost-effective and some that are not.

Step 2: Estimating Cost-Effective Conservation

The Council uses its portfolio model to determine how much conservation is cost-effective to develop. But in order to characterize the conservation potential for this assessment, the Council estimates which measures and programs represented in the achievable supply curve are regionally cost-effective. To do this, the present value of each measure's benefits is compared to the present value of its life cycle costs. Benefits include energy and capacity cost savings, local distribution cost savings and the 10 percent credit given conservation in the Northwest Power Act and any quantifiable non-energy benefits.[14]

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[13] Levelized life-cycle cost is the present value of a resource's cost (including capital, financing and operating costs) converted into a stream of equal annual payments; unit levelized life-cycle costs (cents per kilowatt-hour) are obtained by dividing this payment by the annual kilowatt-hours saved or produced.

[14] To ensure that conservation and generating resources are compared fairly, the costs and savings of both types of resources must be evaluated at the same point of distribution in the electrical grid. Conservation savings and costs are evaluated at the point of use, such as in the house. In contrast, the costs and generation from a power plant are evaluated at the generator itself (busbar). Thus, to make conservation and the traditional forms of generation

The costs included in the Council's analyses are the sum of the total installed cost of the measure, and any operation and maintenance costs (or savings) associated with ensuring the measure's proper functioning over its expected life. The benefit-cost ratio of a measure is the sum of the present value benefits divided by the sum of the present value costs. Any measure that has a benefit-to-cost ratio of 1.0 or greater is deemed to be regionally cost effective. Those measures that pass this screening step are then grouped into "programs. The cost of this package of measures is then increased to account for program administrative expenses to estimate whether the overall package is regionally cost-effective.[15]

The Council incorporates detailed information on the benefits of conservation based on when the conservation produces savings. The Northwest's highest demand for electricity occurs during the coldest winter days, usually during the early morning or late afternoon. Electricity saved during these periods is more valuable than savings at night during spring when snow melt is filling the region's hydroelectric system and the demand for electricity is much lower. However, since the Northwest electric system is linked to the West Coast wholesale power market, the value of the conservation is no longer determined by solely by regional needs.

Part of the value of a kilowatt-hour saved is the value it would bring on the wholesale power market. This assessment uses the Mid-Columbia trading hub (Mid-C) prices from the AURORA forecasting model to represent the wholesale value of electricity saved and thereby gauge cost-effectiveness. Given the interconnected nature of the West, Mid-C wholesale power prices are expected to reflect the demand for summer air conditioning in California, Nevada and the remainder of the desert Southwest. Consequently, wholesale power prices are significantly higher during the peak air conditioning season in July and August than they are during the remainder of the year. Measures, like more efficient air conditioning, reflect the value of these higher prices.

In addition to its value in offsetting the need for generation, conservation also reduces the need to expand local power distribution system capacity and transmission system capacity. The values for this aspect of conservation range from zero for central air conditioning to 1.8 cents per kilowatt-hour for residential space heating depending on when the savings occur relative to system peaks. A more detailed discussion of the time value of conservation savings is in Appendix E: Conservation Cost-Effectiveness Methodology.

Step 3: Identify Development Characteristics

The value of conservation is also determined by how and when it can be developed. The conservation assessment identifies two key characteristics in this regard. First the conservation potential is characterized by whether its timing is discretionary. For conservation measures that are applied to existing buildings, timing is largely discretionary. Whereas for measures in new

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comparable, the costs of the generation plant must be adjusted to include transmission system losses and transmission costs.

[15] In addition to the direct capital and replacement costs of the conservation measures, administrative costs to run the program must be included in the overall cost. Administrative costs can vary significantly among programs and are usually ongoing annual costs. In prior power plans, the Council used 20 percent of the capital costs of a conservation program to represent administrative costs. The Council's estimate of 20 percent falls within the range of costs experienced in the region to date. Therefore, the average cost of all conservation programs is increased 20 percent before being compared to generating resources.

buildings, or equipment, the opportunity to adopt the measure occurs only as fast as new buildings or equipment are put in place. This limits the rate at which these measures can be adopted. However, it also limits the window of opportunity when efficiency upgrades can be captured. This latter category of conservation resources is therefore frequently referred to as "lost opportunity" resources. Furthermore, the conservation assessment identifies the rate at which conservation developments can be accelerated or decelerated. Each bundle of conservation potential has deployment limits.

These constraints include the rate at which programs can be brought online, referred to as the program acceleration or *ramp* rate, the maximum that can be developed in any three-month period, and the maximum ramp-up and ramp-down between quarters. Development of discretionary conservation is limited to a maximum of 30 average megawatts per quarter or 120 average megawatts per year. For lost-opportunity conservation, quarterly development is limited by the physical amount of lost-opportunities available in that quarter. This amount is tied to the growth rate in electricity demand so that in times of high growth, more lost-opportunity conservation is available for development. Less is available in times of low load growth. Lost-opportunity conservation is also constrained in the early years of the forecast period as new programs are brought on line. The maximum penetration of lost-opportunity conservation programs is 15 percent of available stock in 2005 and increases to 85 percent by 2016. The rate at which programs can slow down and the minimum level at which programs can remain viable are also important. The minimum viable level of the program, if above zero, determines the amount of savings that would accrue even though the region would prefer to delay the purchase of the resource during the surplus period. Each program also has an upper limit on its activity level and how quickly the activity level can be reduced (decelerated).

The Council based the ramp rate limits it assumed in its portfolio analysis model on an analysis of historical year-to-year changes in the level of utility conservation. Figure 3-6 shows that year-to-year swings in the amount of utility-acquired conservation in the region have ranged from a decrease of about 70 average megawatts to an increase of nearly 100 average megawatts with multiple "swings" in the 30 - 40 average megawatt range. The Council limited the changes to 80 average megawatts per year.

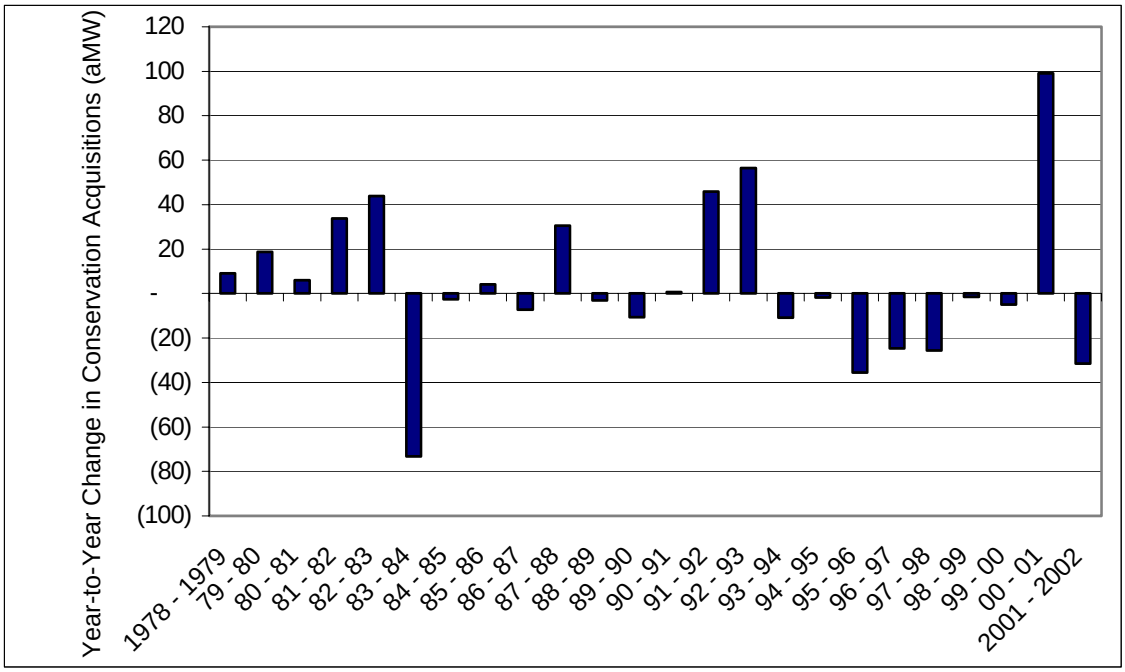

Figure 3-6: Year-to-Year Changes in Northwest Utility-Acquired Conservation

Step 4: Identify Optimal Conservation Development Strategies

The final step in determining the value of conservation savings to the Northwest involves evaluating conservation resources and other resources available for development as part of the regional electricity system. The cost and savings data, the shape of the savings, their capacity value, and the development timing characteristics of conservation are analyzed in the Council's portfolio analysis model. How much conservation to develop is determined by comparing conservation against other resources to find which conservation deployment strategy in combination with development of other resources provides the Northwest with electric service at the least cost while maintaining system reliability at an acceptable level of risk. The results of that analysis are in Chapter 7.

SUMMARY OF ACHIEVABLE CONSERVATION POTENTIAL BY ECONOMIC SECTOR

The following sections summarize the conservation available to the region. The discussion is broken down by economic sectors including residential, commercial, industrial, and agricultural. Cost-effective amounts in these tables are based on medium case forecasts and base-case estimated wholesale prices, not optimized results of the portfolio analysis. Details are available on line at the Council's web site.

A Note about Supply Curves

A supply curve depicts the amount of a product available across a range of prices. In the case of conservation, this translates into the number of average megawatts that can be conserved at various costs. More conservation is available at higher cost, up to a point. This section depicts much of the conservation resource in the form of supply curves. These can be for individual measures or groups of measures. The supply curves used in this draft plan do not distinguish

between conservation resulting from specific programs or consumer response to the price of electricity. Regardless of how the costs of installing a conservation measure are shared, its total cost to the region is the same. The money used to purchase these savings is not available for investment in other resources and goods. If consumers contribute to the purchase of conservation resources, then the cost to the electricity system (i.e., utilities) will be less than the costs presented in this chapter. The costs presented here represent all costs to all participants. This is called total resource cost, or TRC.

Conservation supply curves are a function of the conservation measure's savings and cost. Each measure's savings and cost are used to derive a levelized cost, expressed in cents per kilowatt-hour. The absolute value (in terms of kilowatt-hours per year) of the savings produced by adding a conservation measure is a function of the existing level of efficiency. The less efficient the existing structure or equipment, the greater the savings obtained from installing the measure. In order to minimize the costs of efficiency improvements, conservation measures are applied in order from lowest-cost to highest.[16]

To ensure consistency between the conservation supply curves and the portfolio analysis model, financial assumptions used in the levelized cost calculation are the same as those used in the system models. The portfolio analysis model assumes that conservation will be financed for 15 years or the life of the conservation measure; whichever is shorter, at a real after-tax interest rate of 4 percent.[17]

Residential Sector

The residential sector consumed just over 6,700 average megawatts of electricity in the year 2000, or about 38 percent of the region's non-DSI electricity consumption. Under the medium demand forecast residential loads are expected to grow by about 2,700 average megawatts or 1.36 percent per year from 2000 to 2025. If all of the realistically achievable conservation potential identified in this draft plan is acquired, 2025 residential sector loads could be cost-effectively reduced by 1,275 average megawatts.

Figure 3-7 shows the technical, economic and achievable conservation potential in the residential sector at levelized costs up to over 10 cents per kilowatt-hour. As can be seen from this chart the total economic potential in the residential sector is approximately 1,500 average megawatts by 2025 in the medium forecast. Of this amount the draft plan estimates that 1,275 average megawatts of conservation savings can be realistically achieved by 2025.

[16] Least cost is defined in terms of a measure's levelized life-cycle cost, stated in cents per kilowatt-hour. Levelized cost is used so that measures with different lifetimes and savings can be compared on a uniform basis.

[17] In practice, consumers and/or utilities may decide to pay cash or "expense" their conservation investments. While this increases the "up front" cost of the savings it avoids the interest cost associated with financing and therefore would produce a lower levelized cost than shown here.

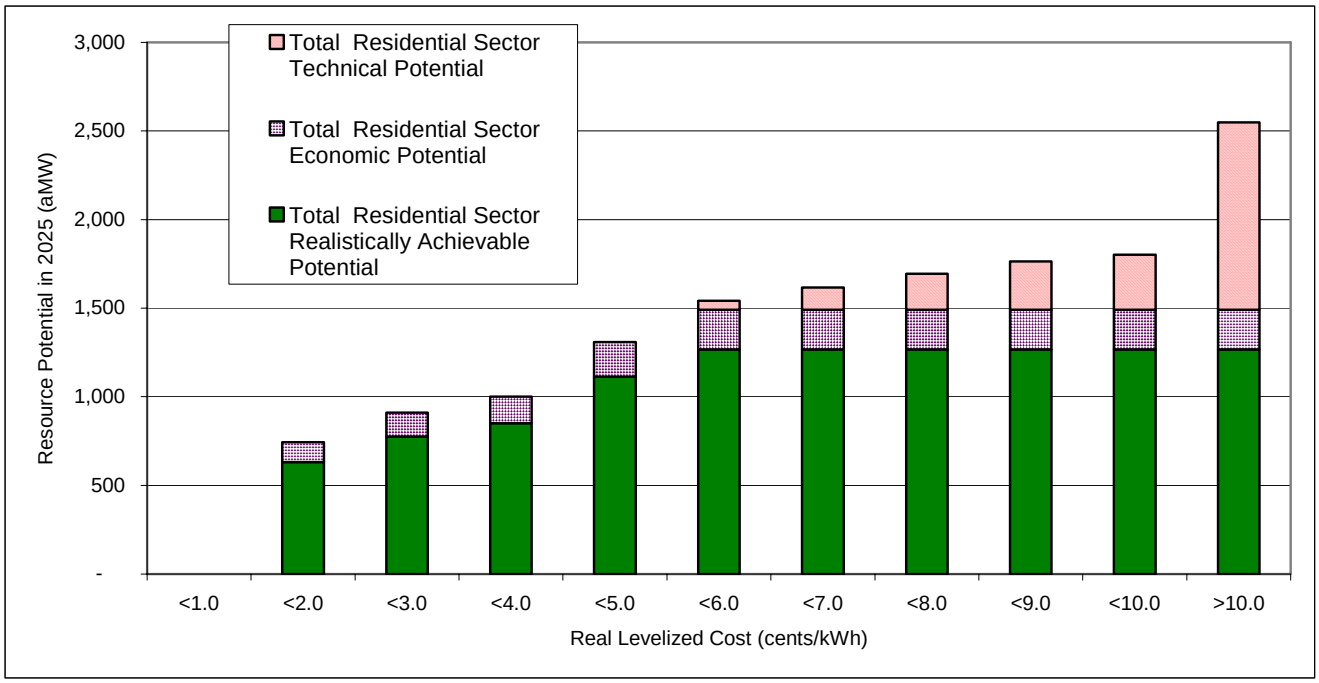

Figure 3-7: Residential Sector Technical, Economic and Achievable Conservation Potential by 2025 under Medium Forecast

Major residential sector conservation opportunities have been identified that will reduce the anticipated demand for space conditioning (i.e., heating and cooling), water heating, lighting, clothes and dish washing and refrigeration. Figure 3-8 shows the source of the savings among the major end uses of electricity in this sector. The largest resource potential (41 percent) is estimated to be available from improvements in residential lighting.

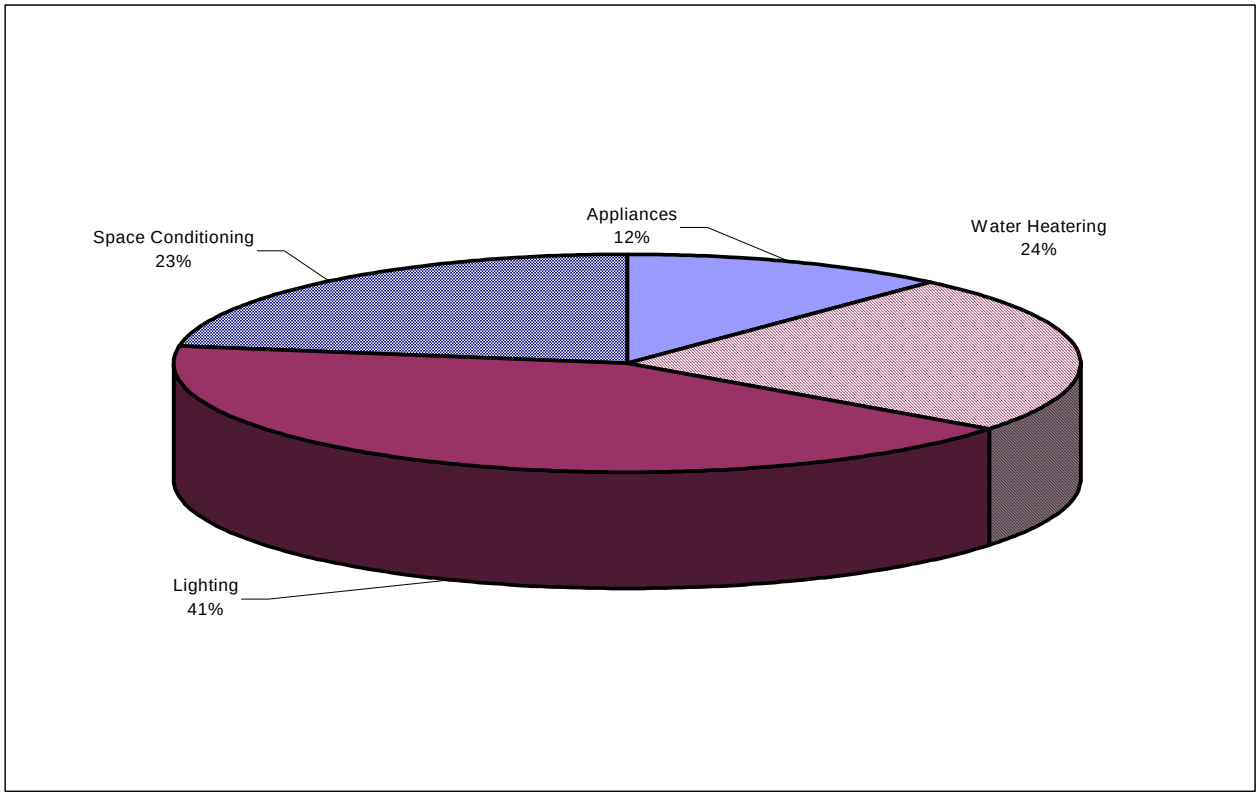

Figure 3-8: Residential Savings Potential by End Use

Improvements in water heating and space condition efficiency each constitute about one-fourth of the achievable potential. More efficient appliances comprise the remainder of this sector's potential. The following section discusses the major findings of the Council draft conservation assessment for this sector.

Residential Space Conditioning

Although thousands of the electrically heated homes in the region have been retrofitted and improved energy codes require that new homes be built more efficiently, not all cost-effective conservation opportunities in existing and new homes have been, or are being, captured. Figure 3-9 shows the technical, economic and achievable savings potential in residential space conditioning. This draft plan identifies cost-effective conservation savings in existing site-built and manufactured/mobile homes that could reduce year 2025 demand for electricity by 285 average megawatts. These savings are available at an average total resource cost of 3.1 cents per kilowatt-hour.

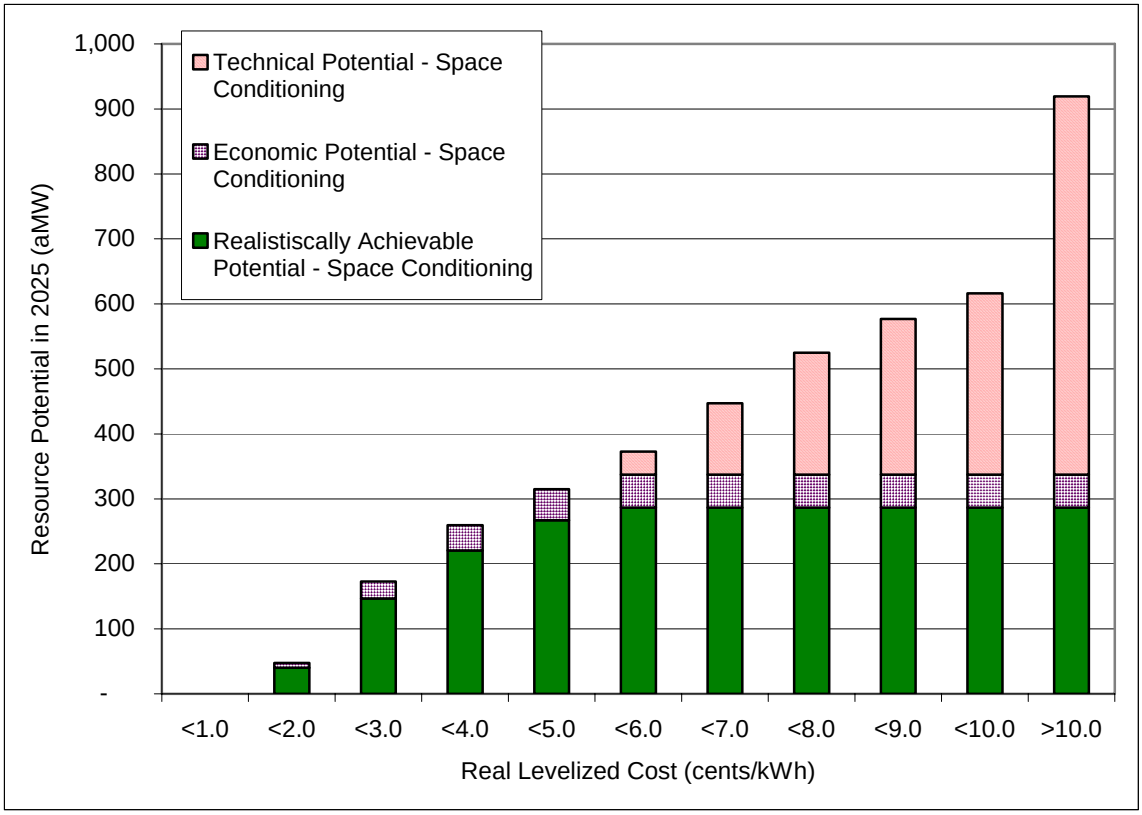

Figure 3-9: Residential Space Conditioning Conservation Resource Potential

Approximately one-third of the achievable space conditioning conservation potential can be acquired through weatherization of existing site-built and manufactured homes. Improving the efficiency of both existing and new heating systems through either converting them to heat pumps or installing a higher efficiency heat pump represents about half of the space conditioning conservation potential. Sealing duct work in homes with electric forced-air heating systems and "commissioning" heat pumps to ensure their refrigerant charge is correct and that they have adequate air flow across their heating coils each represent about 3 percent of the achievable potential. The remaining 12 percent of the potential comes from improvements in the efficiency of new site-built and manufactured homes.

This is the first Council plan to identify the conversion of existing forced-air and zonal (baseboard, wall & radiant) heating systems to high efficiency air-source heat pumps as a cost-effective conservation option. This plan, also for the first time, identifies cost-effective conservation savings opportunities from reducing the "leaks" in forced-air distribution system ductwork and from proper installation of air-source heat pumps. These options would not have been available had it not been for regional market transformation activities supported by the Northwest Energy Efficiency Alliance and its utility partners. However, while the transformation of this market may yet occur, it appears that in the near term local utility programs will need to target these measures in order to capture their savings.

Residential Lighting

The single largest residential sector conservation opportunity identified in this draft plan is the replacement of incandescent lamps with compact fluorescent lamps (CFLs). As noted previously, recent improvements in product quality (size, color rendition, "instant start," etc.) and dramatically lower product prices have increased the size of this conservation resource by nearly tenfold. Over the next 20 years the region could reduce lighting use in the residential sector by 530 average megawatts at a total resource cost of 1.7 cents per kilowatt-hour.

The Northwest has been quite successful in its efforts to deploy improved compact fluorescent lighting over the past several years. In the future, both regional market transformation efforts and continued local utility programs will be necessary to capture this large resource. Market transformation efforts should focus on improving product quality and features that promote consumer acceptance (color, multi-wattage, dimming capability, etc.) while utility programs can address the lack of awareness and higher incremental cost barriers faced by this technology.

Residential Appliances

Figure 3-10 shows that 150 average megawatts of cost-effective conservation is estimated to be achievable by 2025 from improvements in residential appliances. The average total resource cost of these savings is 4.9 cents per kilowatt-hour.

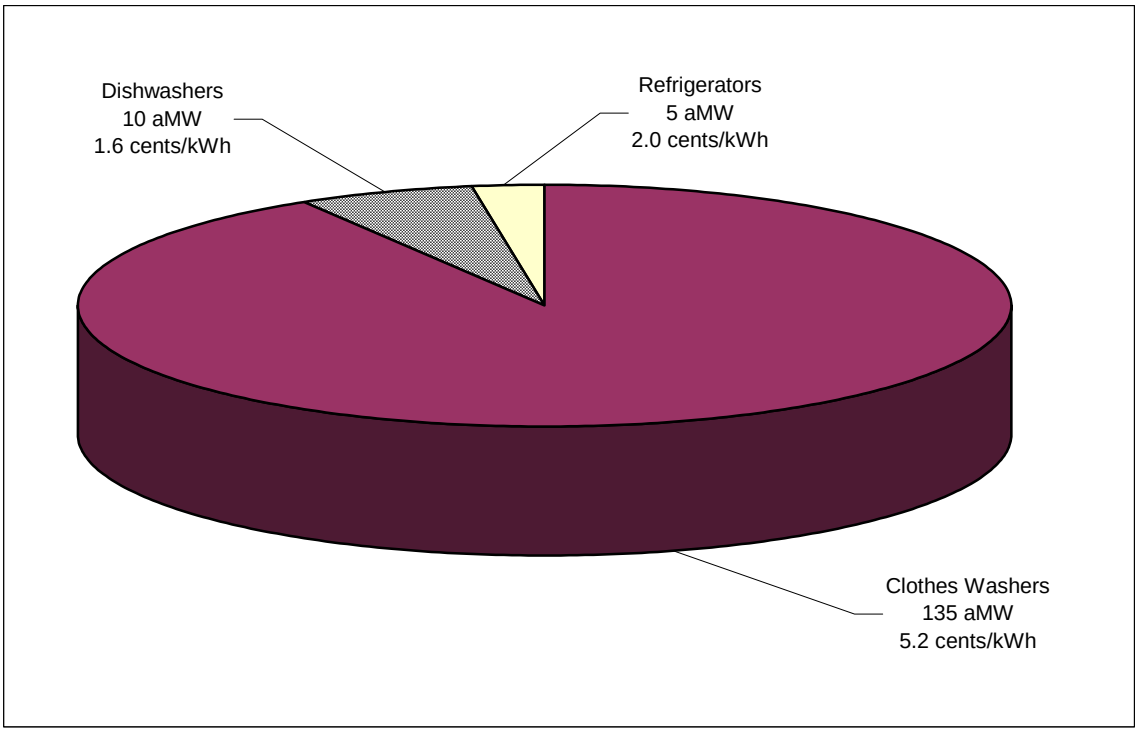

Figure 3-10: Realistically Achievable Conservation Potential in Residential Appliances

Savings from more efficient clothes washers represent over 90 percent of the savings available from the use of more efficient residential appliances. Despite the recent adoption of higher efficiency standards for residential clothes washers, advancements in technology have made even higher levels of efficiency cost-effective. New clothes washers are available that are 50 percent

more efficient than the 2007 federal standard. While savings from clothes washers have a relatively high levelized cost (5.2 cents per kilowatt-hour) they are regionally cost-effective from a total resource cost perspective due in large part to their significant "non-energy" benefits. These washers require much less water and detergent. Therefore they save the region both water and wastewater treatment costs as well as energy costs.

The small amount of conservation potential available from improvements in residential refrigerators and freezers is due to the fact that a new federal standard took effect in 2001 that increased efficiency by approximately 30 percent. On average, a typical new refrigerator now uses less than 500 kilowatt-hours per year, down from over 1,000 kilowatt-hours less than a decade ago. Consequently, a 10 percent improvement in efficiency only nets about 50 kilowatt-hours per year of savings -- about the same as replacing one incandescent lamp with a CFL.

On the other hand, recent product offerings from some refrigerator manufacturers have increased the differential between the new federal standard and their products, with some models exceeding the federal standards efficiency by as much as 20 percent. While there are as yet too few models to determine whether this level efficiency is cost-effective, the Council intends to review this issue prior to issuance of its final Fifth Power Plan.

Residential Water Heating

Four major technologies were investigated to assess their ability to cost-effectively reduce residential water heating use. The new federal standards that took effect in January of 2004 require that a 50-gallon electric water heater achieve and Energy Factor (EF) of not less than 0.904. Despite the improvements required by the new federal standards, even higher levels of tank efficiency can produce cost-effective savings. Installation of better-insulated tanks instead of ones that just meet the new federal standard could produce regional savings of over 80 average megawatts by 2025 at a total resource cost of 2.2 cents per kilowatt-hour.

In addition to improvements in tank efficiency which only reduce "standby" losses, two other technologies are available that reduce the amount of electricity needed to heat the water in the tank. The first of these technologies employs a small heat pump to extract heat from the air and release it inside the tank. Current commercially available water heating heat pumps are capable of achieving over 240 percent improvements in the efficiency of water heating. Application of this technology, due to its high cost (4.3 cents per kilowatt-hour) and its larger physical size has been limited to not more than one-quarter of the region's single family and manufactured homes. However, even with this limitation, the use of heat pump water heaters could produce regional savings of 195 average megawatts by 2025.

Heat pump water heaters have been commercially available since the early 1980s. In fact the first Council plan anticipated that they would achieve significant market penetration by the year 2000. This has not proven to be the case. Consequently, the region needs to undertake a deliberate program to achieve the cost-effective savings available from this technology. This will likely require a demonstration project of that is both regional in nature and of significant scale. The primary problem facing the deployment of this technology is its current high incremental cost and the lack of a regional distribution network -- barriers that cannot be overcome by individual utility programs.

Solar water heating is the third technology option for reducing electricity use for residential water heating. While this technology clearly has promise, at its current price it was not identified providing a regionally cost-effective resource option. Figure 3-11 shows the major sources of residential water heating conservation potential.

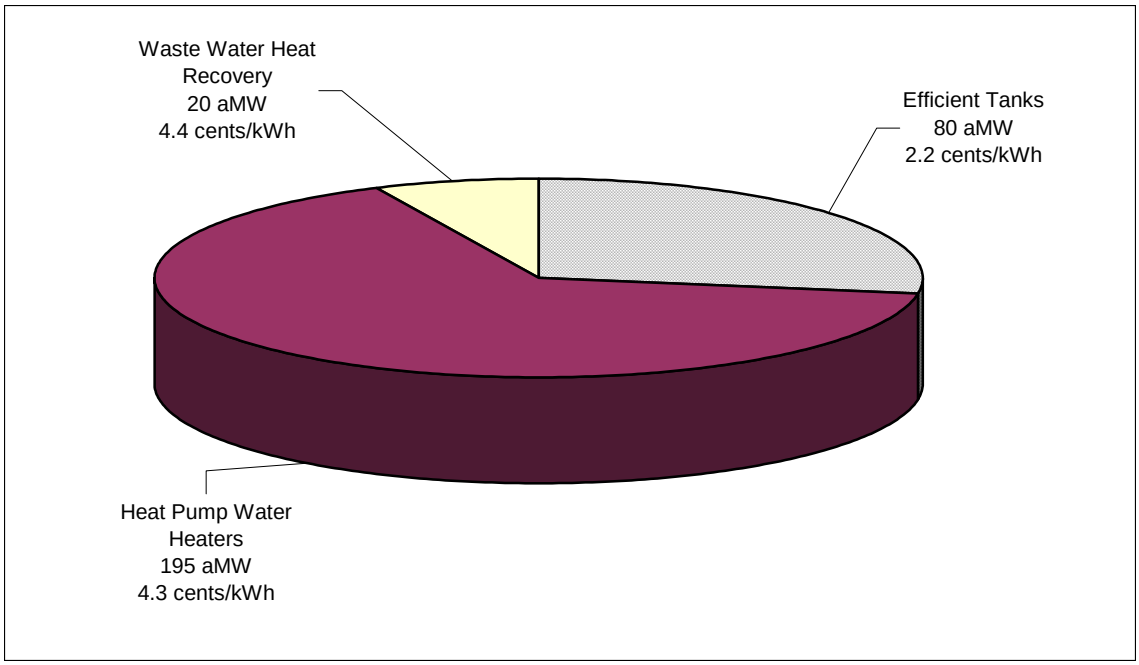

Figure 3-11: Realistically Achievable Conservation Potential in Residential Water Heating in 2025

The fourth technology that can cost-effectively reduce future residential water heating use recovers waste heat from shower drain water to pre-heat the shower's cold water supply. This recent technology innovation employs the fact that drain water adheres to the sides of a pipe as it falls downward. The phenomenon, referred as "gravity film adhesion," permits heat to be recovered from the shower drain water. By the year 2025 installation of this technology in new single family and multifamily dwellings could save the region 20 average megawatts at a total resource cost of 4.4 cents per kilowatt-hour.

The achievable potential for this measure could be significantly increased (perhaps by as much as fivefold) if it were adopted in state energy code requirements for new residential construction. In the near term, both regional market transformation efforts and local utility incentives will likely be required to capture this resource.

Dispatchable and Lost Opportunity Resources in the Residential Sector

Approximately half, 650 average megawatts, of the achievable resource potential in the residential sector is comprised of "dispatchable" conservation resources. These resources can be scheduled for development any time during the next twenty years. On the other hand, the remaining half, 625 average megawatts, of the achievable conservation resources in this sector must be acquired at the time of their construction, replacement or installation. Once programs are capturing 85 percent of lost-opportunities this amounts to between 30-35 average megawatts per year. Based on their total resource cost, the region (utilities and consumers) would need to

allocate approximately $125 million annually to acquire these "lost-opportunity" resources. If the region were to acquire the dispatchable residential sector conservation resources in equal annual amounts (20-25 average megawatts) over the next twenty years the total resource cost of doing so would be approximately $60 million per year.

Commercial Sector

The commercial sector consumed just over 5,200 average megawatts of electricity in the year 2000, or about 30 percent of the region's non-DSI electricity consumption. About 88 percent of this is used in buildings with the remaining amount used in infrastructure systems like water supply, sewage treatment, street and highway lighting, traffic signals, broadcasting and other non-building systems that are part of our economy. Under the medium forecast, commercial loads are expected to grow to by nearly 1,800 average megawatts or 1.18 percent per year from 2000 to 2025. If all of the realistically achievable conservation potential identified in this draft plan is acquired, 2025 commercial sector loads could be cost-effectively reduced by about 1,100 average megawatts under the medium forecast.

The draft commercial conservation assessment evaluated about 100 measures for possible inclusion in the supply curve. All told, nearly 1,600 average megawatts of technical conservation potential were identified in the medium forecast as shown in Figure 3-12. The assessment covered building systems, equipment and infrastructure. Nearly 90 percent of the conservation identified is cost-effective based on expected average wholesale market prices. Estimating that 85 percent of the conservation is practically achievable leaves a cost-effective and achievable resource of over 1,100 average megawatts that could be developed over the forecast period in the commercial sector. That is about 16 percent of medium forecast 2025 commercial sector loads. The average levelized cost of the cost-effective and achievable conservation is 2.1 cents per kilowatt-hours (2000$).

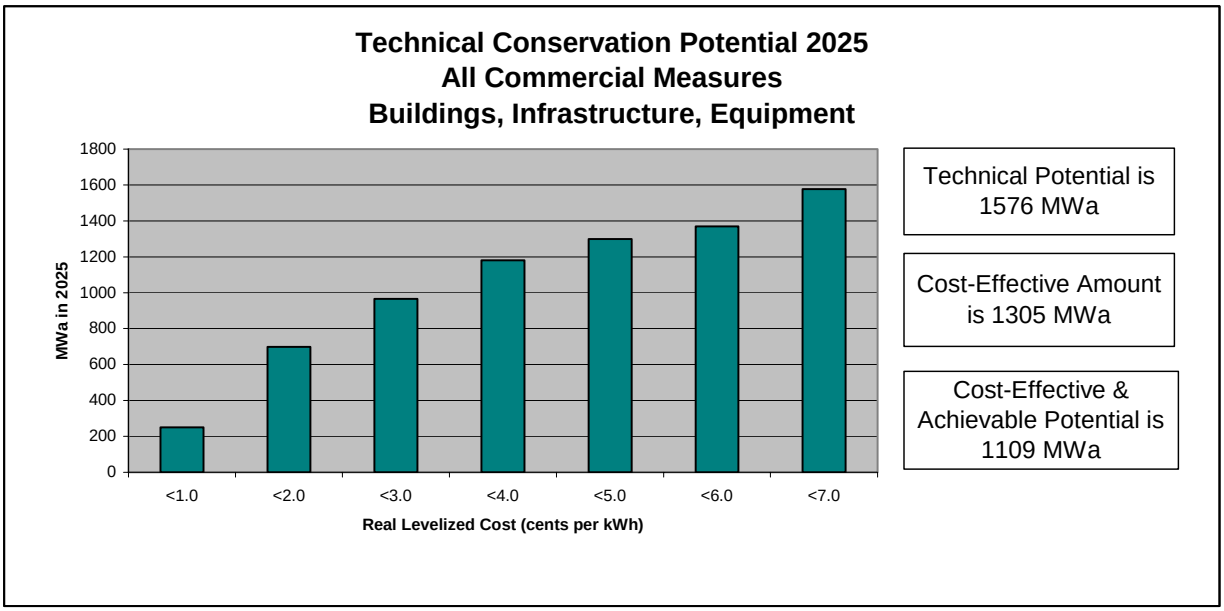

Figure 3-12: Commercial Sector Technical Conservation Potential

Figure 3-13 shows that about 60 percent of the cost-effective and achievable savings is lost-opportunity conservation. About two-thirds of the savings is in building lighting, heating, cooling, ventilation, and air-conditioning systems. The other third is divided between equipment and infrastructure systems.[18] Savings from commercial lighting measures the largest single end-use contributing to the savings potential. Tables 6 and 7 list the commercial sector measures lost-opportunity and retrofit measure bundles discussed in this section.

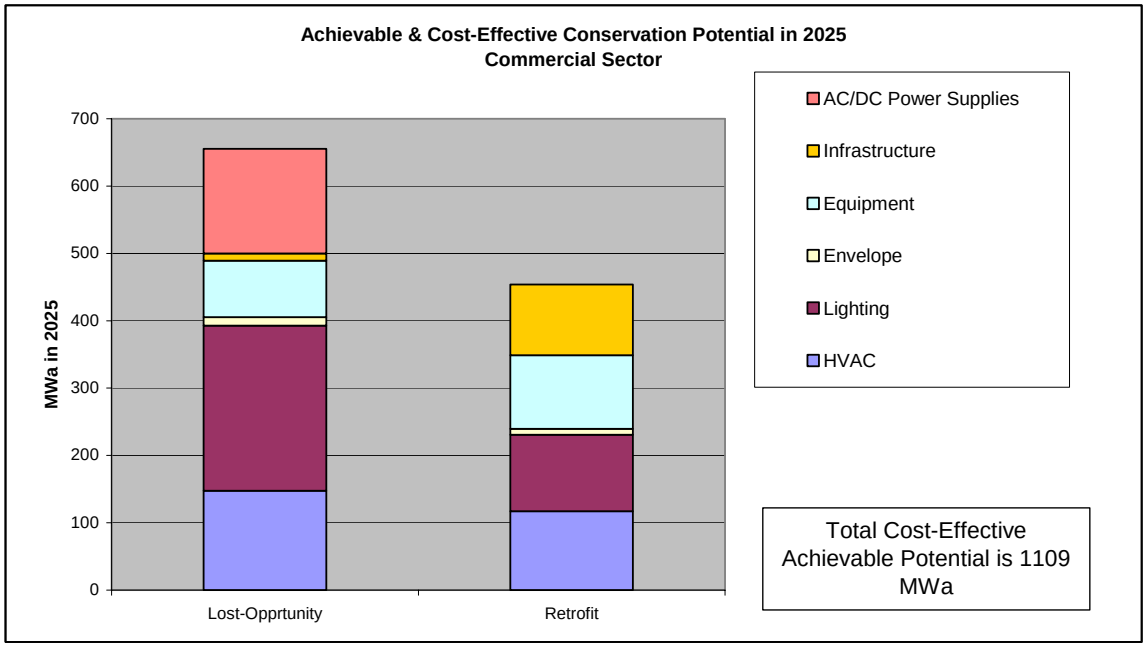

Figure 3-13: Commercial Lost-Opportunity and Retrofit Conservation

[18] Part of lost-opportunity potential, from more efficient AC/DC power supplies, occurs in the residential and industrial sectors.

Table 3-6: Commercial-Sector Retrofit Measures

Lost-Opportunity Measure	Realistically Achievable Potential in 2025 (MWa)	Weighted Levelized Cost (Cents/kWh)	Benefit/Cost Ratio
Efficient AC/DC Power Converters	156	1.5	2.7
Integrated Building Design	155	2.3	4.7
Lighting Equipment	125	0.3	12.3
Packaged Refrigeration Equipment	68	1.9	1.9
Low-Pressure Distribution	47	2.7	1.6
Skylight Day Lighting	34	3.4	1.6
Premium Fume Hood	16	3.7	1.0
Municipal Sewage Treatment	11	1.4	2.4
Roof Insulation	12	1.5	2.1
Premium HVAC Equipment	9	4.3	1.2
Electrically Commutated Fan Motors	9	2.4	1.8
Controls Commissioning	9	3.7	1.1
Variable Speed Chillers	4	3.1	1.6
High-Performance Glass	1	2.8	0.7
Perimeter Day Lighting	1	6.3	0.9
Evaporative Assist Cooling	0	0.0	0.0
Total	**655**	**1.8**	**4.7**

Table 3-7: Commercial-Sector Retrofit Measures

Retrofit Measure	Realistically Achievable Potential in 2025 (MWa)	Weighted Levelized Cost (Cents/kWh)	Benefit/Cost Ratio
Lighting Equipment	114	1.8	2.2
Small HVAC Optimization & Repair	75	3.2	1.4
Network Computer Power Management	61	2.8	1.3
Municipal Sewage Treatment	37	1.4	2.4
LED Exit Signs	36	2.3	1.6
Large HVAC Optimization & Repair	38	3.7	1.2
Grocery Refrigeration Upgrade	34	1.9	1.9
Municipal Water Supply	25	3.3	1.2
Office Plug Load Sensor	13	3.1	1.2
LED Traffic Lights	8	1.9	1.8
High-Performance Glass	9	2.9	1.3
Adjustable Speed Drives	3	4.3	1.1
Total	**454**	**2.5**	**1.7**

Commercial Retrofit Measures in Buildings

Most of the electricity used in the commercial sector is used to light buildings, provide comfortable controlled climates, and to operate equipment. Despite the performance of conservation programs over the last 20 years and improving codes and standards, there is still a great deal of viable conservation opportunity in building lighting and HVAC systems for both new and old buildings. Figure 3-14 is the supply curve for building-related conservation measures for retrofit conservation in the existing building stock. Of the nearly 400 average megawatts of achievable potential, nearly 300 average megawatts is cost-effective, with benefit-to-cost ratios greater than 1.0.

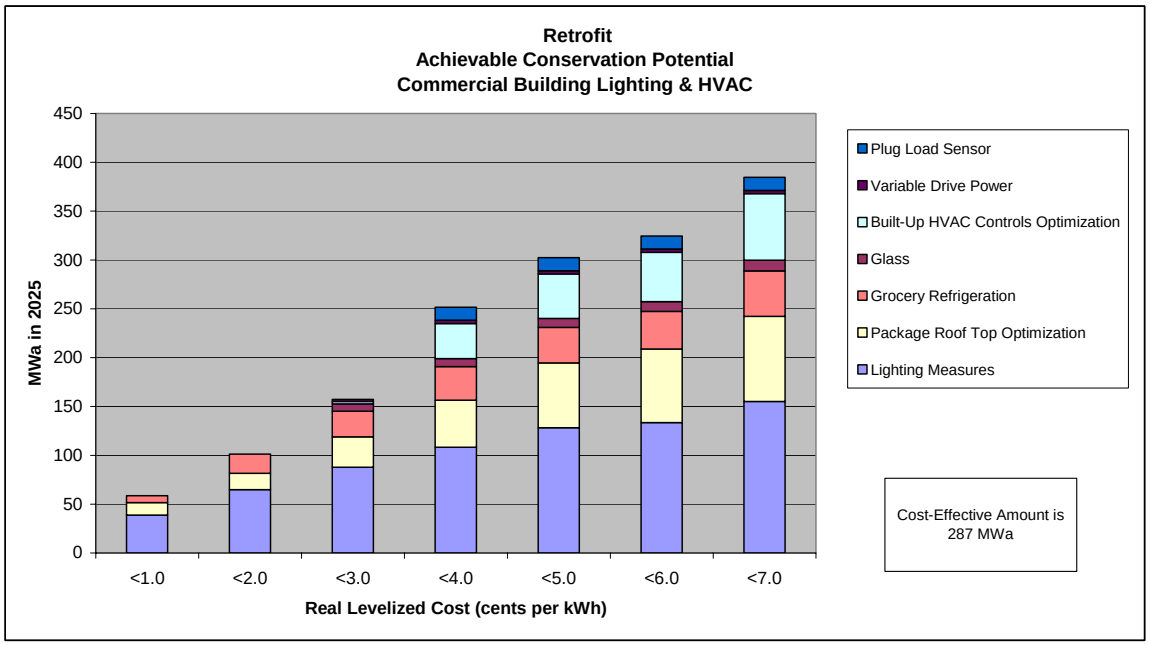

Figure 3-13: Retrofit Conservation in Commercial Buildings

Commercial Retrofit Lighting

Much of the retrofit potential is in lighting measures. Under medium case assumptions 114 average megawatts is cost-effective at an average cost of about 1.8 cents per kilowatt-hour and a benefit-cost ratio of 2.2. Since the Fourth Power Plan there has been continued evolution in commercial fluorescent lighting technology. Improved lamp phosphors, lamp barrier coatings, gas fills and ballast electronics have achieved impressive new levels of efficiency, color quality and longevity. Four-foot fluorescent lamps are the workhorse of commercial lighting. New high-performance fluorescent systems reach efficiencies of almost 100 lumens per watt. That's nearly double the efficacy of new systems commonly installed a decade ago. Improvements in high-ceiling applications yield significant new savings opportunities. There have also been significant strides made toward more efficient options for display lighting used in retail applications.

There are about 20 commercial lighting measures in the commercial sector assessment. These measures represent a cross section of lighting applications specific to building and lighting equipment types. Technologies include:

- High-performance T8 lamps paired with high-performance ballasts (HPT8) replacing T12 and first-generation T8 systems in the 4-foot and 8-foot fixture markets[19]
- Pulse-start metal halide fixtures replacing standard metal halide
- High-output linear fluorescents (T5HO and HPT8) replacing metal halide fixtures in high-ceiling applications
- Ceramic metal halide and halogen infrared lamps replacing incandescent display lighting in retail applications
- Compact fluorescent lamps and fixtures replacing incandescent and smaller standard metal halide fixtures

Technological improvements in high-performance T8 lamps paired with high-performance ballasts (HPT8) provide large savings over older T12 lamps and ballasts. And the new systems are cost-effective in many cases when replacing T8 lamps and ballasts installed as recently as the early 1990s. HPT8 systems can provide better quality light at a 50 percent savings over older T12 systems and a 20-30 percent savings over first-generation T8 lamps and ballasts.

Cost premiums for the new lamps are modest, about $1.00 per tube over standard T8 lamps. This premium is expected to remain in place due to the higher cost of the phosphor ingredients in the high-performance systems. But high-performance ballast costs are falling, and for at least one major manufacturer there is no ballast cost premium for high-performance ballasts. In many applications a two-lamp high performance T8 system can replace three- or four-lamp systems providing lower re-lamping costs over the life of the system due to fewer lamps required, and longer lamp life, even at higher lamp prices.

Increasing the penetration of high-performance T8 technology will not be easy. Presently there is a dizzying array of fluorescent lamp and ballast choices. Getting high quality lighting and energy savings will require careful system specification and application as well as efforts to get the products to market. Programs to help simplify choices and provide easy system design parameters would go a long way to improve the successful rollout of this technology.

Another significant new technology application is the use of high-output linear fluorescent fixtures instead of metal halide fixtures in high-ceiling applications like warehouses and big box retail stores. High-output linear fluorescent fixtures including HPT8 and T5HO systems offer efficiency improvement of about 50 percent over standard metal halide fixtures. The linear fluorescent systems also provide better color rendition, less light depreciation over time and the ability to restart instantly. The instant restart advantages allow the fluorescent systems to be used more easily in combination with occupancy or day lighting controls. But metal halide systems are still significantly less expensive on a first-cost basis.

The Northwest has been quite successful in its past efforts to retrofit commercial-sector lighting. In the future, both regional efforts and continued local utility programs will be necessary to capture this large resource. Market transformation efforts should focus on improving product availability and the education and training needed to assure quality retrofit applications. There are several commercial sector lighting markets that need to be addressed including retail display lighting, high-ceiling applications, and office lighting systems. Local acquisition programs can

[19] T8 and T12 refer to the diameter of the fluorescent tubes in eights of an inch. A T8 tube is one-inch in diameter.

address the lack of awareness and higher incremental cost barriers faced by these measures. Eventually, building codes can be improved to incorporate lower lighting power densities.

Optimizing Commercial Package Roof-Top HVAC Units

The second-largest slice of the commercial retrofit potential is in optimizing packaged rooftop HVAC units (75 average megawatts at a levelized cost of 3.2 cents per kilowatt hour and a benefit/cost ratio of 1.4). By far the single most common HVAC system in the commercial sector is the package rooftop system. These systems are typically fairly small unit sizes that provide gas heating and electric cooling and ventilation to portions of commercial buildings. Despite the fact that they are mass-produced and installed, these systems are notoriously problematic. Control and damper malfunctions are common and have been well documented by regional studies. The conservation potential in this category includes the following measures: economizer repair, coolant charge correction, coil cleaning, and demand-control ventilation. Much of the savings result from repairing economizers to perform up to their potential. Economizer operation reduces the need for operating air conditioning compressors by using outside air to cool spaces when possible. The Pacific Northwest climate is particularly well suited to this technique. Developing the savings from these measures will require significant research to verify savings and cost, training and education, development of protocols for diagnosis and repair, and significant acquisition incentives. It is a set of measures that may or may not be suitable for market transformation but would benefit greatly from region-wide cooperation on development and deployment strategies.

An emerging technology that may supersede these measures is the development and use of packaged evaporative-assist cooling units. Several manufacturers are developing such devices that could significantly improve cooling system performance for packaged rooftop units increasing the size of the potential in this category and possibly lowering its cost. These devices are particularly well suited to the Pacific Northwest climate with its warm dry summers. Savings from evaporative assist cooling have not been included in the resources assessment because the technology is not widely available for simple packaged systems. However, products are emerging and the region should proceed with some demonstration projects for this technology.

Other Commercial Building Retrofit Measures

The remainder of the retrofit supply curve includes several measures. Optimizing built-up HVAC control systems (38 average megawatts at 3.7 cents per kilowatt-hour and benefit/cost ratio 1.2) is one or the more expensive sets of measures in the assessment. This measure set includes diagnosis, repair and commissioning of buildings with complex HVAC systems. Grocery refrigeration (34 average megawatts cost-effective at 1.9 cents per kilowatt-hour and benefit/cost ratio 1.9) includes 17 specific measures for grocery store refrigeration systems. Retrofitting single-glazed windows in electrically-heated buildings (9 average megawatts at 2.9 cents per kilowatt-hour and benefit/cost ratio 1.3), installing occupancy sensor controls for certain office equipment (13 average megawatts at 3.1 cents per kilowatt-hour and benefit/cost ratio 1.2) and retrofitting variable-load fans and pumps with variable-speed drives or adjustable speed drives (3 average megawatts at 3.1 cents per kilowatt-hour and benefit/cost ratio 1.6) represent the remainder of the identified retrofit conservation potential. These measures are best developed primarily through direct acquisition incentives of local utilities and system benefit

charge administrators and secondarily through market transformation ventures and infrastructure support.

New Commercial Buildings, Renovations, Remodels and System Replacements

By 2025 about 40 percent of the building stock will be buildings built after 2002 under medium case assumptions. Even though building codes have undergone tremendous improvements for efficiency, technology and building design practice present further opportunities for energy efficiency. In addition to new structures, this category contains many measures that apply to building energy systems that are replaced due to events including tenant remodels, full building renovations, conversion from one use to another and equipment burn out.

Conservation measures in this category are lost-opportunity measures in that they only occur at the time a new building is built or a system or piece of equipment is replaced. In this category measure costs and savings are incremental to what would be installed absent attention to efficiency. The baseline against which efficiency options are measured is the applicable building code, or if superior, standard practice. For example, if an entire office lighting system were replaced as part of a remodel, the baseline system would be 1.1 watts per square foot in code, not the 1.5 watts per square foot of the old system. But data from a recent survey show that common-practice in new office lighting systems is 1.0 watt per square foot. Common practice is more efficient than code. An efficient HPT8 system could be installed at 0.8 watts per square foot. The savings counted in this assessment are only the difference between the common-practice system and the efficient system or 0.2 watts per square foot in this example. Costs are the incremental costs of the more efficient equipment and any extra labor required.

Figure 3-15 represents the achievable conservation supply curve for lost-opportunity conservation in new buildings, renovations, remodels and system replacements. About 550 average megawatts are available, of which about 420 is cost-effective.

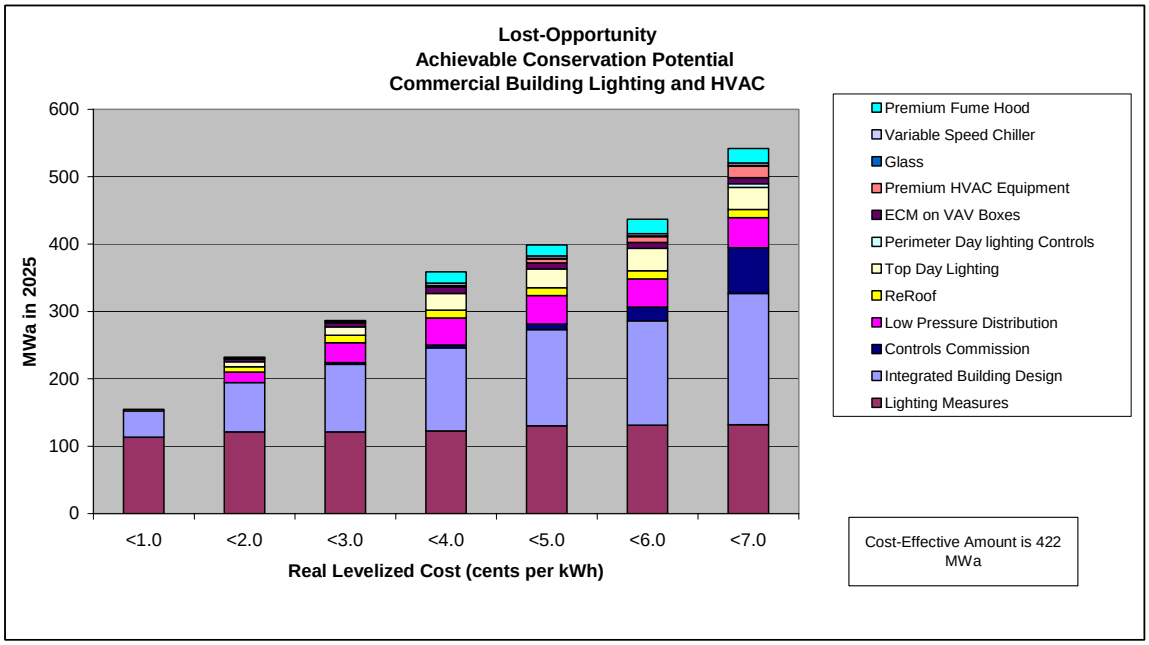

Figure 3-15: Lost-Opportunity Conservation in Commercial Buildings

New Commercial Building Lighting Measures

Many of the lighting measures in this curve are similar to their counterparts in the retrofit supply curve. But their costs and savings are lower. The new building lighting measure bundle contains 18 measures based on the same technologies used in the retrofit measures. But their application in new buildings is at lower cost than in the retrofit case. Savings are lower too, because the baseline from which savings are estimated is lower. There is a potential for 125 average megawatts at 0.3 cents per kilowatt-hour. Several hundred combinations of lighting technology, building type and space heat fuel characteristics comprise the measure bundle to capture the range of costs and interactive effects on space heating and cooling energy use from reduced lighting energy. The measures are applied only to the estimated fraction of new floor space that is not already at high-efficiency lighting power density levels. The low levelized cost of the new-building lighting measures is due in part to reduced re-lamping and maintenance costs of high-performance systems where fewer lamps can provide equivalent light and last longer.

New building lighting measures also include sky lighting in one-story retail stores, warehouses and schools (34 average megawatts at 3.4 cents per kilowatt-hour and benefit/cost ratio of 1.6) as well as a small amount of potential from perimeter day lighting control in some offices beyond the manual switching required in the predominant codes.

New building and replacement lighting measures are available now, but significant education, training, marketing are needed to develop these measures to their full potential. These measures are ripe for a combination of local incentives and market transformation ventures. Considerable regional cooperation and infrastructure are needed for education, training, marketing and specification setting because of the many options available to designers and lighting installers and a confusing array of products.

New Commercial Building System Commissioning Measures

Commissioning energy systems in new buildings is another significant source of savings in the new building supply curve. The estimate for such measures is 9 average megawatts at 3.7 cents per kilowatt-hour. Building commissioning is a systematic process of ensuring that the energy consuming systems in a building work together as intended and can be maintained to continue to do so. It involves a commissioning plan developed in the design-phase, specified functional testing of systems, and the development and implementation of operations and maintenance plans and training. The estimates of cost and savings of this measure have been modified from those in the Fourth Power Plan for several reasons. Foremost is a significant increase in estimated new building commissioning costs based on recent evaluation studies in and outside the region. Another factor is that the baseline assumes a significant amount of building commissioning is already taking place in new buildings as a result of changing design and construction practices as well as some elements of the building code in the Seattle area.

New Commercial Building Integrated Design

The largest measure bundle in the new building category is integrated building design. The potential is estimated to be 155 average megawatts at 2.3 cents per kilowatt-hour. This is a set of measures that, when applied in an integrated fashion at the design stage of new buildings provide

synergies that increase savings or reduce costs when compared to the application of individual measures. For example, during the design process of a large new office building, the selection of glazing is an important step with complicated interactions between heat loss, solar heat gain, glazing area, external shading, orientation, day lighting considerations, and the sizing of the HVAC systems in the building. Savings due to energy-optimized glazing selection provide synergistic savings and reduced the size and cost of HVAC systems required to condition the building. In many cases capital costs of the bundle of integrated measures net to zero.

Integrated design is only viable as a measure for a fraction of the new building stock. It requires some additional design costs and design team interaction and is more likely to be adopted in projects that are developed by long-term owners. This assessment applies the measure to a fraction of new building floor area that ranges from 20 percent to 70 percent depending on building type.

The technologies in the integrated design bundle include many of the same lighting, HVAC and envelope technologies and commissioning reviewed and deployed individually in new buildings. But their savings are marginally higher because of synergies between measures and the ability to capture capital cost reduction from down-sized equipment, avoided systems and redirected capital. The savings are about evenly split between lighting and HVAC end uses.

Acquisition approaches for new building integrated design measures should be a combination of market transformation, regional infrastructure development, and local program assistance. In most cases, the key is to get energy considerations into the building design process at an early stage. Another element needed is developing demand among owners for efficient buildings. Identifying likely candidates and finding ways to intervene early enough in the design process to make a difference requires thoughtful and sometimes expensive marketing approaches. There are many submarkets for commercial building design depending on building type and ownership patterns. Because of these characteristics of the design market, achieving energy savings through design practice changes is best pursued at a regional level since designers operate across all utilities. Local utility incentives can be focused on extra design costs. The region has made some good progress along these lines in recent years through market transformation programs run by the Northwest Energy Efficiency Alliance. Continued and expanded efforts are needed.

Other New Commercial Building Measures

Many of the measures in this curve are available only in new buildings or when new equipment is purchased. The measures are briefly described below.

- Low-pressure distribution systems (47 average megawatts at 2.7 cents per kilowatt-hour) are an emerging design practice that includes raised floors, efficient diffusion of air and dedicated outdoor air systems to reduce the energy required to deliver heating, cooling and fresh air to buildings. These measures are probably best approached as design practice changes through market transformation efforts
- High-performance glazing (1 average megawatts at 3.7 cents per kilowatt-hour) represents glazing systems that are better than code and optimized for minimizing heating and cooling requirements. These measures are probably best approached as design practice changes through market transformation efforts

- Reroofing with extra insulation (12 average megawatts at 1.5 cents per kilowatt-hour) is a measure that is available only at the time of reroofing and is cost-effective for buildings heated with electricity. This is good measure for local utility programs
- Premium HVAC equipment (9 average megawatts at 4.3 cents per kilowatt-hour) primarily represents installing package rooftop HVAC equipment with higher cooling performance than specified in code. Regional and national market transformation efforts are needed in the near term combined with local utility incentives to capture these savings
- Variable speed chillers (4 average megawatts at 3.1 cents per kilowatt-hour) can be installed as replacement chillers in hospitals, large offices and other built-up HVAC systems. Their part-load efficiency is much improved over modular constant-speed chillers, and they are particularly useful in the mild Pacific Northwest climate. Regional and national market transformation efforts are needed in the near term combined with local utility incentives to capture these savings
- Premium fume hoods (16 average megawatts at 3.7 cents per kilowatt-hour) are new designs for laboratory safety exhaust hoods that require much less air flow and fan horsepower to perform their safety functions. These hoods can save 50 percent to 70 percent over hoods commonly in use today and dramatically reduce the amount of energy needed to condition make-up air. This measure is probably best approached through regional market transformation or regional infrastructure development with significant utility incentives in the early stages.

Commercial Infrastructure and Equipment

The Fifth Power Plan considers conservation potential in several areas not evaluated in previous plans. These are summarized in the infrastructure and equipment categories in Figure 3-16. This analysis yielded about 400 average megawatts of cost-effective and achievable conservation potential.

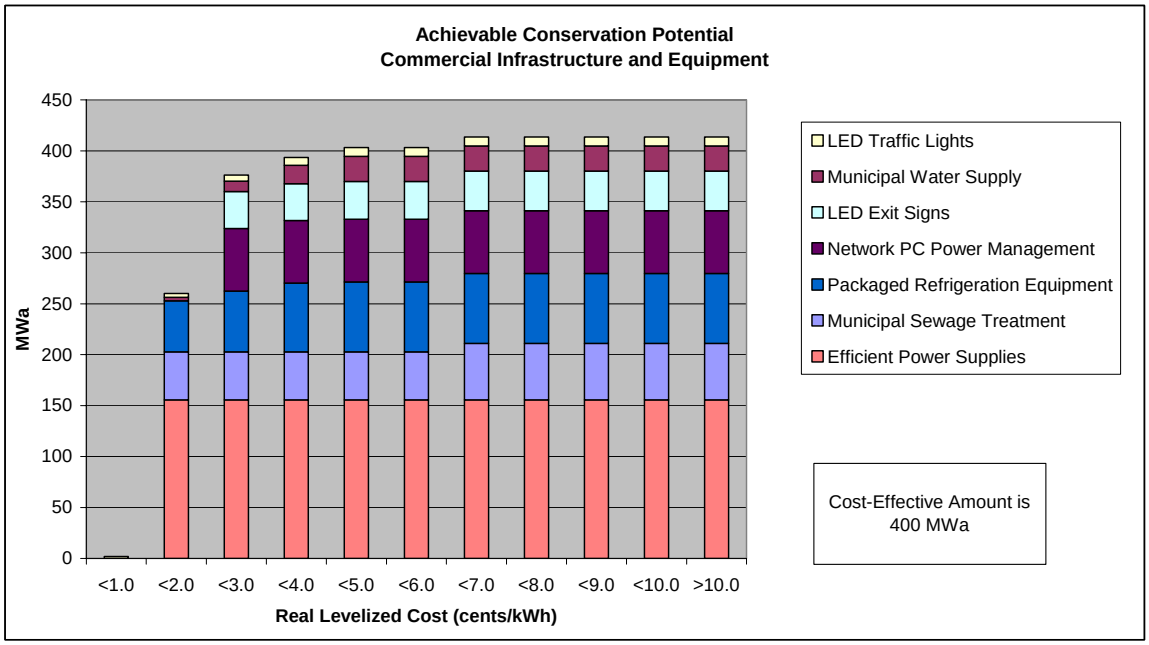

Figure 3-16: Achievable Conservation Potential in Commercial Infrastructure and Equipment

Figure 3-17 divides the commercial infrastructure and equipment into lost-opportunity and retrofit categories. About 60 percent is in lost-opportunity category.

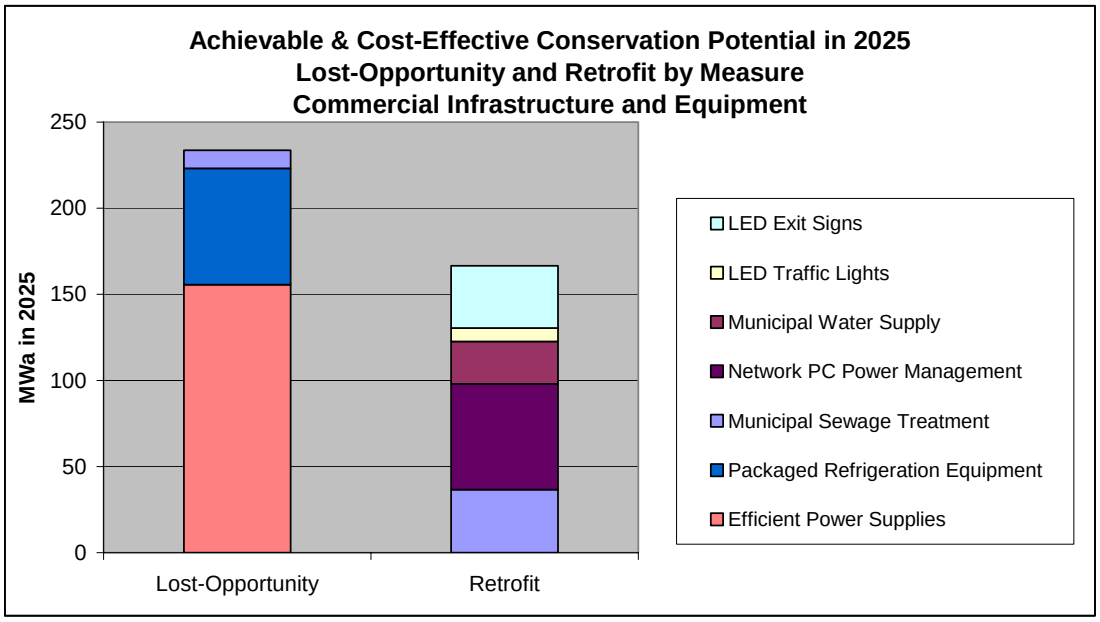

Figure 3-17: Achievable and Cost-Effective Potential in Infrastructure and Equipment

Lost Opportunity Measures in Commercial Infrastructure and Equipment

The lost-opportunity supply curve appears in Figure 3-18. The lost-opportunity conservation potential is dominated by efficient power supplies and efficient packaged refrigeration units.

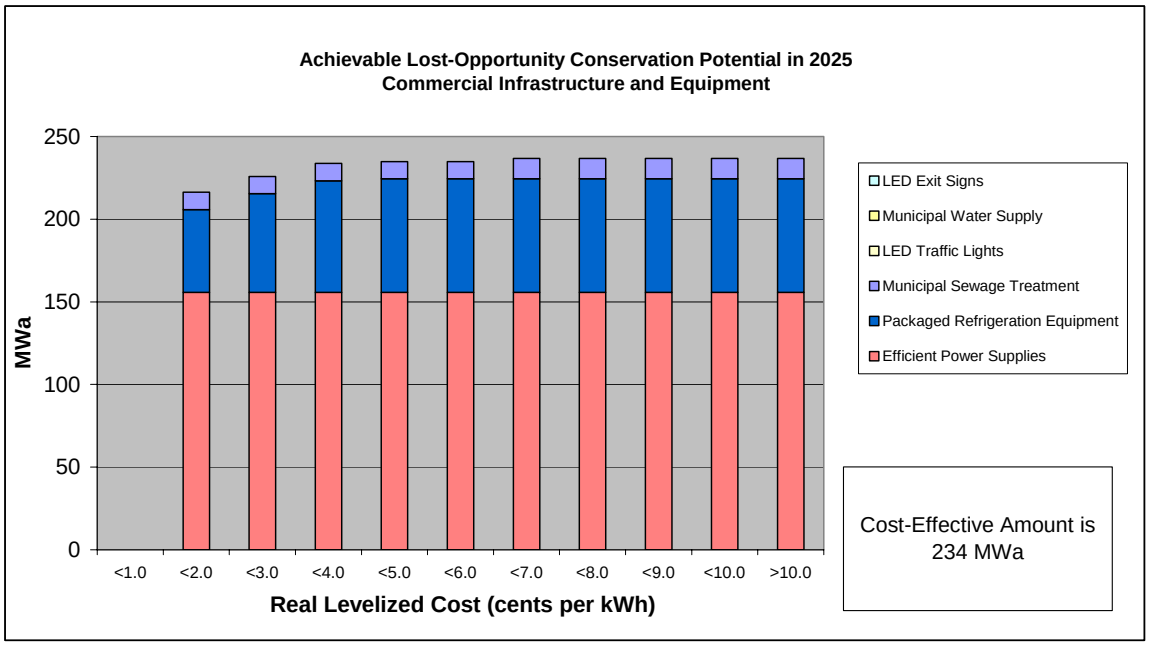

Figure 3-18: Lost Opportunity Potential in Infrastructure and Equipment

Efficient Power Supplies

Many electric and electronic devices in use in the Pacific Northwest operate on direct current (DC) power. There are approximately 100 million of these devices in the Northwest embedded in televisions, VCRs, computers, monitors, furnaces, answering machines, credit card machines, phone chargers and many other devices.

Within these devices, small transformers convert alternating current (AC) power to direct current (DC) power. There is an efficiency loss when power is converted from AC to DC. Efficiency of typical small transformers ranges 50 percent to 75 percent depending on the transformer and how heavily it is loaded. Improvements in the design of these small transformers and conversion to solid-state technology provide significant improvements. For example, the transformers in desktop computers typically operate in the 70 percent efficiency range at 30 percent load factor. New solid-state transformers can increase the efficiency to the 85 percent range. While savings at the individual appliance level are small (49 kilowatt-hour/year in the case of a personal computer), the huge number of these devices makes the total savings potential quite large -- 156 average megawatts at 1.5 cents per kilowatt-hour or less. The potential identified here is for all sectors of the economy, residential, commercial and industrial. The cost cited here is based on the incremental cost of an efficient power supply for a personal computer. These measures are good candidates for market transformation ventures and national standards.

Packaged Refrigeration Units

Efficient commercial refrigerators, freezers, icemakers, beverage machines and vending machines represent another set of measures not previously identified in any regional power plan. This is stand-alone equipment is used in restaurants, schools, hospitals and the lodging industry. Design and equipment advances made in the residential refrigeration market have not been realized in commercial units. The potential is large, and cost is low -- 68 average megawatts at 1.9 cents per kilowatt-hour. Savings from efficient units range around 50 percent and can go higher. In one recent research project, efficiency designers worked with a major manufacturer and reduced consumption a their solid-door reach-in refrigerator by 68 percent from 9 kilowatt-hour per day to 2.9 kilowatt-hour per day. The improvements were from brushless DC evaporator fan motors, changed face frame design, reduction of anti-sweat heater wattage, and changed refrigerant to R-404A. The net cost for these improvements was zero.

The estimated potential uses a baseline of the 2003 California standards and takes into account existing penetration of Energy-Star qualifying units. Cost estimates are based on several recent studies. Ultimately these measures are good candidates for state standards and market transformation projects at the state, regional and national levels. In the near term, acquisition incentives may be needed to stimulate demand.

Retrofit Measures for Commercial Infrastructure and Equipment

Figure 3-19 shows the retrofit supply curve for commercial infrastructure and equipment. About 180 average megawatts has been identified, most of which is cost-effective.

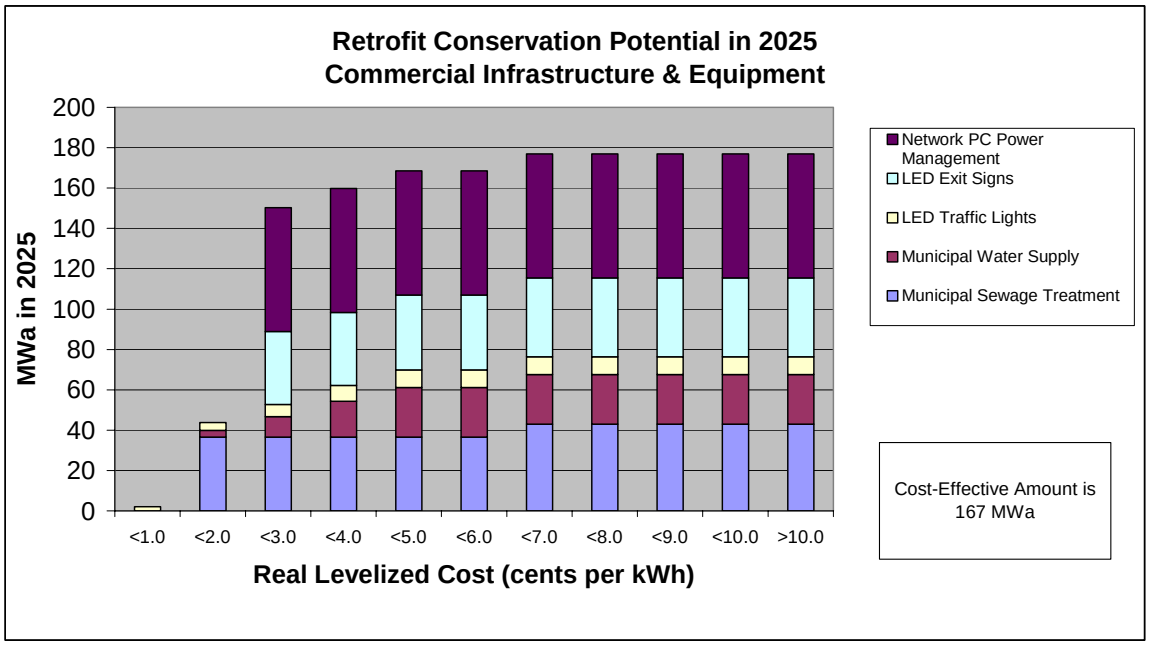

Figure 3-19: Retrofit Measures in Infrastructure and Equipment

Network Personal Computer Power Management

Network personal computer power management is the automatic control of systems that can turn computers and monitors off when not in use. This software allows companies to take full advantage of the energy-saving capabilities inherent in today's personal computers. The measure provides a network administrator the capability of monitoring energy use of networked computers and remotely powering down desktop computer systems when not in use. The potential is estimated to be 61 average megawatts at 2.8 cents per kilowatt-hour.

LED Exit Signs

Exit signs in new buildings are predominantly efficient using light-emitting diodes (LED), compact fluorescent (CFL) or electro-luminescent (EL) light sources. While an estimated 20 percent of exit signs in existing buildings use these technologies, the other 80 percent are still using incandescent signs. Exit signs are on all the time, and the savings from moving to one of the efficient technologies are significant: 100 to 250 kilowatt-hours per sign per year depending on the base case sign and the technology chosen. Six measures and applications were used to estimate costs and savings. There is also significant labor and lamp replacement savings over the life of the signs as the lamp life of the efficient models is much longer than the incandescent signs. The potential is 36 average megawatts at 2.3 cents per kilowatt-hour.

LED Traffic Lights

The application of green and red LEDs to the traffic signal market has been swift. Many signals across the region have already been changed out, but there are more to do. Red signals were the first to change due to their lower cost. Green LED signals are now cost-effective and being adopted in many jurisdictions. Ten measures by color and size were used to estimate costs and savings. The estimated remaining potential, 8 average megawatts at 1.9 cents per kilowatt-hour, is based on phone surveys of many municipal, county and state jurisdictions.

Municipal Sewage Treatment

This is another new measure in the power plan. Treating municipal sewage uses an estimated 300 average megawatts across the Pacific Northwest. The optimization of sewage treatment processes through improved process controls can yield significant energy, and maintenance savings particularly in small to mid-sized wastewater treatment plants. Savings are in reduced pumping and aeration costs. Appropriately adjusted controls can also deliver other benefits by helping plants comply with water quality regulations and better manage sludge accumulation, chlorination and de-chlorination, effluent, ammonia and odors. Costs and savings for this measure were estimated from a Northwest Energy Efficiency Alliance pilot program and work in California. Five applications of the technology in different sizes and for different treatment processes make up the supply curve. The levelized cost of this measure is greatly reduced by significant non-energy benefits. The estimated potential is 37 average megawatts at 1.4 cents per kilowatt-hour. The measure is best developed through a combination of market transformation and direct acquisition.

Municipal Water Supply

Supplying clean water to municipalities uses about 120 average megawatts of electric energy per year across the Northwest. Many of the same process controls used in wastewater management, plus improvements in leak detection technology, can be tapped to produce savings in municipal water supply. The estimated potential is 25 average megawatts at 3.3 cents per kilowatt-hour. The costs and savings of these measures are more uncertain than those for wastewater because the region has not run any pilot programs to demonstrate savings.

Irrigated Agriculture

Irrigated agriculture consumed approximately 650 average megawatts of electricity in the year 2000, or about four percent of the non-DSI electricity consumption in the region. This sector's loads are forecast to increase by approximately 30 average megawatts by 2025 or about 0.17 percent per year. If all of the realistically achievable conservation savings identified in this draft plan can be captured, irrigation loads can be cost-effectively reduced by about 11percent in 2025.

Figure 3-20 shows the technical, economic and achievable conservation potential in the irrigated agriculture sector at levelized costs up to over 10 cents per kilowatt-hour. As can be seen from this chart, the total economic potential in the residential sector is approximately 95 average megawatts by 2025 in the medium forecast. Of this amount the draft plan estimates that 80 average megawatts of conservation savings can be realistically achieved by 2025 at an average total resource cost of 2.7 cents per kilowatt-hour.

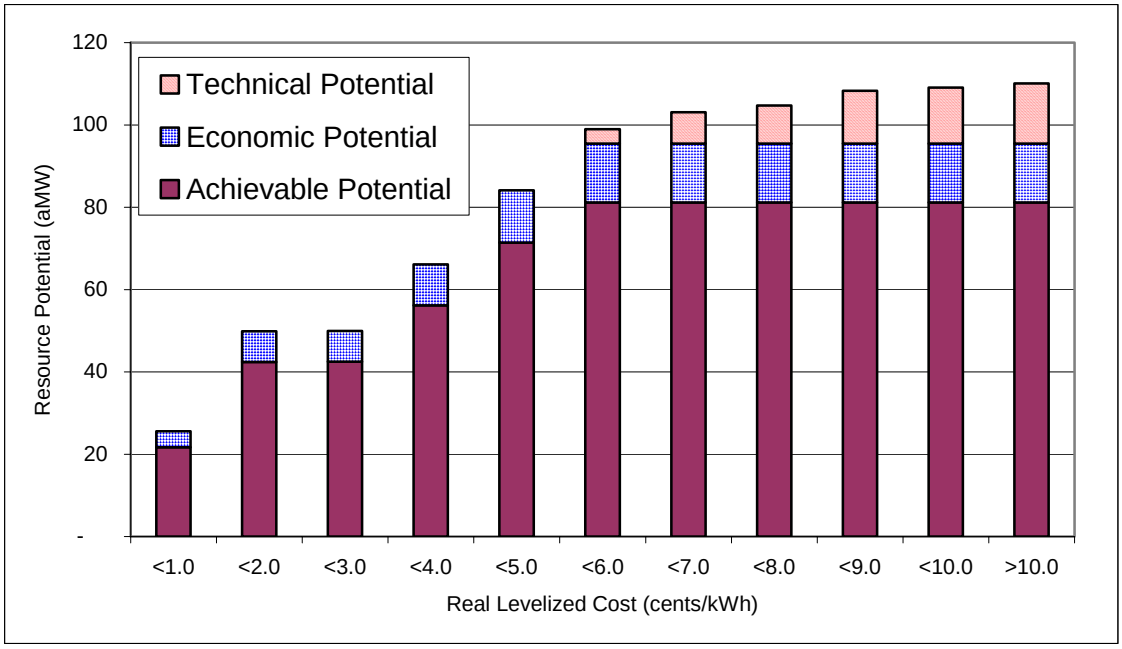

Figure 3-20: Energy Conservation Potential in Irrigated Agriculture

Between 1987 and 1997 the amount of irrigated land in the region increased just under 10 percent or about 760,000 acres. The greatest increases in irrigated acreage were in Oregon, followed by Idaho and Washington. Only in Montana did irrigated acreage remain roughly unchanged over the decade. However, despite the increase in irrigated land, electricity use in this sector actually decreased by about ten percent between 1994 and 1997. This was largely a result of conversion from high-pressure to low-pressure center-pivot irrigation systems.

Figure 3-21 shows the market share irrigated by center-pivot systems at three different operating pressures. As can be seen from a review of Figure 3-21, the decrease in high-pressure center-pivot market share has been offset in the market share of low-pressure center pivot systems. Low-pressure systems not only require significantly less energy for pumping than do high-pressure systems, they also reduce the amount of water evaporated into the air. This results from the fact that they spray water downward rather than upward and also apply it over a smaller area. With less evaporation more water can be applied to crops with the same number of kilowatt-hours or the same amount of water can be applied with fewer kilowatt-hours. Converting the remaining acreage of high- and medium-pressure center-pivot irrigation systems to low-pressure systems could collectively save 30 average megawatts for less than 1.4 cents per kilowatt-hour.

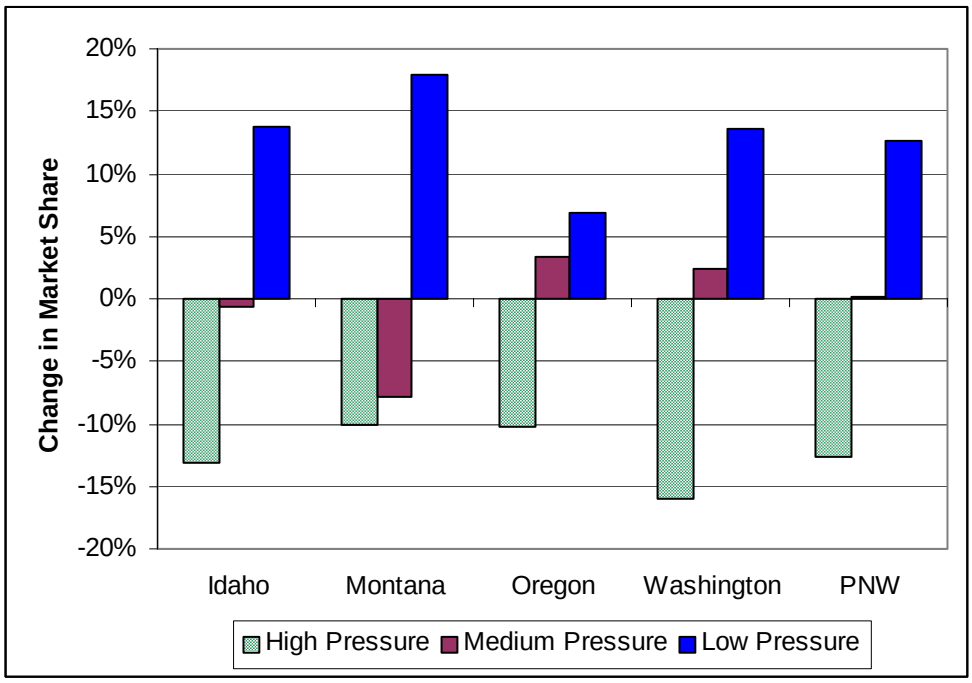

Figure 3-21: Change in Market Share of High- Medium- and Low-Pressure Center-Pivot Irrigation Systems 1994 to 1997

In addition to reducing system-operating pressures, improvements in the efficiency of irrigation are possible through the use of higher efficiency pumping and by reducing system friction losses and water leaks. As shown in Figure 3-22, the largest single source of cost-effective achievable potential in the irrigation sector comes from the replacement of existing pumps with higher efficiency ones, reducing leaks by replacing worn gaskets and installing new spray nozzles. Savings from this measure could total 35 average megawatts at a total resource cost of 3.3 cents per kilowatt-hour. An additional 15 average megawatts of savings are available at a total resource cost of 4.7 cents per kilowatt-hour through reductions in leakage and nozzle replacements on existing irrigation systems where existing pumping systems are already efficient.

Dispatchable and Lost-Opportunity Resources in the Irrigated Agriculture Sector

All 80 average megawatts of the achievable resource potential in the irrigated agriculture sector are "dispatchable" conservation resources. These resources can be scheduled for development any time during the next 20 years. If the region were to acquire the dispatchable agricultural sector conservation resources in equal annual amounts (4 average megawatts per year) over the next 20 years the total resource cost of doing so would be approximately $7 million per year. Most of these measures and practices are best acquired through a combination of local utility conservation acquisition programs combined with technical assistance to irrigators.

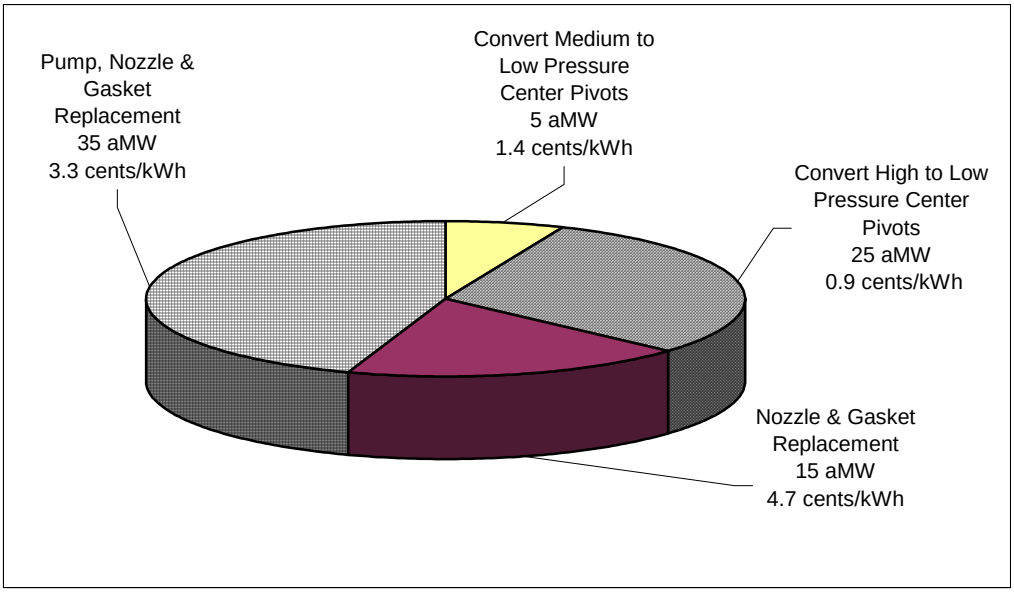

Figure 3-22: Achievable Conservation Resource Potential in Irrigated Agriculture

Industrial Sector

The non-DSI industrial sector consumed approximately 4,800 average megawatts of electricity in the year 2000, or about 27 percent of the non-DSI electricity consumption in the region. This sector's loads are forecast to increase by approximately 2,300 average megawatts by 2025 or about 1.58 percent per year. The Council estimates that, at a minimum, there is a 5 percent savings from this sector that is both cost-effective and achievable. That amount would be about 350 average megawatts on forecast 2025 non-DSI industrial electric loads.

The Council has not done any primary research on industrial potential for this Draft Fifth Power Plan. However, to formulate an estimate of savings from the non-DSI industrial sector, the Council reviewed industrial sector analyses recently completed for the Northwest Energy Efficiency Alliance and the Energy Trust of Oregon as well as a survey of business management practices regarding energy in major Northwest industries performed for the Alliance. The Council also reviewed recent utility reports of industrial-sector conservation achievements and reports of industrial conservation activity from the Energy Trust and industrial participation in the Oregon Business Energy tax Credit. These sources all corroborate that significant potential remains for industrial energy savings in the Pacific Northwest.

The study done for the Energy Trust of Oregon identified a technical savings potential of 32 percent over 10 years in the industrial sector in Oregon, distributed among some 26 specific measures or practices.[20] About 85 percent of the savings was estimated to be cost-effective given assumptions used by the Trust, with an average cost well below 1 cent per kilowatt-hour. Presuming 85 percent of the economic potential is practically achievable, overall savings potential identified is on the order of 23 percent of industrial electric use.

[20] "Energy Efficiency And Conservation Measure Resource Assessment For The Residential, Commercial, Industrial And Agricultural Sectors." Prepared for the Energy Trust of Oregon, Inc. by Ecotope, Inc., The American Council for an Energy Efficient Economy (ACEEE), and Tellus Institute, Inc., January, 2003.

The Alliance study found a regional technical potential of 682 average megawatts and an achievable potential of 545 average megawatts.[21] This analysis identified a series of measures and practices that are applicable across all industries. It also evaluated industry- and process-specific savings for five major Northwest industries: pulp and paper; wood products; food processing; transportation equipment; and microelectronics. The overall achievable savings potential in the Alliance study is about 13 percent of forecasted non-DSI industrial load assumed by the Alliance. Cost estimates by the Alliance ranged in the 1 to 2 cents per kilowatt-hour levelized cost. Both the Alliance study and the Trust study identify similar energy-saving opportunities that are briefly discussed below.

The study of business practices performed for the Alliance found that Northwest businesses are comparable to other businesses in the United States and around the world with regard to the use of management practices for energy and energy costs[22]. The study indicates industrial-sector businesses have much room for improvement in the way they manage energy and energy costs. Thirty Northwest businesses participating in the study were rated at one or two stars on a scale where five stars is the top rating and reflects "best practices." Companies rated with two stars tend to be focused in cutting out obvious waste of energy, but don't have consistent and systematic processes for continuing to generate improvements and sustain them.

As part of the Fourth Power Plan, the Council did an extensive review of industrial sector conservation supply estimates performed by others. Results of that analysis led the Council to believe an 8-percent reduction in non-industrial electric loads was achievable and cost-effective overall. Individual sector potential ranged from 5 to 11 percent. Prior Council estimates also cited industrial conservation potential in the range of 7 to 9 percent of electric consumption for the sector as a whole. These earlier estimates were based on several different methods of analysis. The 1983, 1986 and 1989 estimates were based on industrial customer response to surveys. The 1991 Council estimate was based on an end-use model and supplementary data from energy audits.

Industrial Energy Use

As shown in Table 3-8, according to market research done for the Alliance, motors and motor systems used approximately 2,500 average megawatts or just over half of the electricity consumed in the non-DSI industrial sector in 2000. Compressed air systems used another 10-percent while lighting represented around 5-percent of total sector electricity use.

[21] Industrial Sector Initiative, Northwest Energy Efficiency Alliance, Third Review Draft, May 22, 2004.
[22] One-2-Five® Energy Market Research Program Results, EnVinta Corporation for the Northwest Energy Efficiency Alliance, May 2004.

Table 3-8 - Major Uses of Electricity in the Non-DSI Industrial Sector

End Use	Estimated Load (aMW)	Share of 2000 Industrial Loads
Compressed Air	510	11%
Motor and Motor Systems	2500	52%
Refrigerated Warehouses	110	2%
Lighting	240	5%
Other	1476	31%
Total	4836	100%

Industrial Conservation Measures and Practices

In the industrial sector, substantial savings are available from measures that apply across facility and process types. These crosscutting measures include motors and motor-driven systems, lighting, compressed air, and electrical supply systems. Other measures are industry-, or process-specific. These include specific technologies or system optimization such as refrigeration optimization in food processing and storage, improved conveyance systems, ultra-violet and microwave drying, membrane technology in chemicals industries and carbon dioxide purging systems in controlled-atmosphere storage facilities.

Most of the electricity consumed by industry is used in electric motors that drive a variety of systems. Electric motors are used in pumps, fans and blowers, compressed air systems, material handling, conveyance, material processing, and refrigeration. There are three kinds of efficiency improvements possible in these systems. Taken together, these three approaches can yield savings on motors and the systems they drive in the range of 10 to 15 percent.

First, more efficient motors can be used. Motors are inherently efficient devices, and the implementation, in 1997, of the minimum-efficiency standards in Energy Policy Act of 1992 (EPAct) eliminated the least-efficient products from the new-motor market. More recently, the motor manufacturers trade association, National Electrical Manufacturer's Association (NEMA), in cooperation with the Consortium for Energy Efficiency agreed upon voluntary minimum standards for "premium" efficiency motors up to 500 horsepower. NEMA members are now promoting the use of these "premium" motors to their customers. Savings from premium motors are typically in the 1 to 4 percent range depending on size and motor loading.

Second, even greater savings can be realized through improvements in the efficiency of the systems that electric motors operate. These include both the selection of more efficient pumps, fans and compressors as well as significant savings from correctly sizing the equipment to meet operating demands. This frequently involves removing dampers and pressure-reducing valves, and reducing system pressure instead by slowing the fans or trimming pump impellers. In many

cases, the motor that runs the system can then be downsized, moving its operating point into a range of greater efficiency. Typical savings are 6 percent for fan systems and 15-20 percent for pumping systems.

Third, motor and drive systems savings can be achieved through system optimization. This approach requires a systematic evaluation of the process system to determine the optimal flow and pressure requirements serviced by the motor system. These evaluations can be time-consuming and often require the use of external engineering contractors. However, the savings achieved through system optimization can be dramatic – often exceeding 50 percent of initial system electricity use.

Industrial lighting systems offer another crosscutting industrial efficiency opportunity. Industrial lighting systems can be fairly complex due to the application-specific nature of the designs, demanding performance requirements and sometimes-harsh operating environments. But the high-performance lighting technologies available in commercial building systems can provide cost-effective savings at industrial facilities as well. Up to 50 percent improvement in the efficacy of high-ceiling applications systems are particularly attractive measures. And 10 to 15 percent improvements are available from new high-performance T8 fluorescent systems over the standard T8 fluorescent systems used in industrial office space and low ceiling manufacturing areas. Conservatively, 15 to 20 percent of industrial lighting energy could be saved cost-effectively. This amounts to about 40 average megawatts. In addition to energy savings, substantial productivity and safety benefits have been documented to result from improved industrial lighting designs. Unfortunately, designers with industrial lighting experience are in short supply.

Compressed air systems are also used throughout industry, primarily to operate tools. These systems account for about 10 percent of non-DSI industrial electric use. These systems are convenient for plant workers and managers, but are notoriously inefficient and offer easy opportunities for cost-effective savings. There are many measures employed when optimizing compressed air systems, ranging from reducing leaks to the application of sophisticated sensors and controls on modular multiplexed compressor banks. Typical savings are in the 5 to 15 percent range.

Tuning up electric supply systems in industrial facilities is another cross cutting opportunity. Two measures have wide applicability. First, over- or under-voltage conditions and unbalanced phases can significantly reduce the efficiency of motors by up to 5 percent while also leading to premature equipment failure. Surveys have indicated that these conditions are far more common than previously recognized. Second, high-efficiency transformers are available to convert distribution voltage to plant voltage. Both load and no-load losses can be reduced by 40 to 50 percent, which translates into a one- to two-percent reduction in electric bills.

Finally, there is a wide array of process-specific and industry-specific conservation opportunities. Savings available in process modifications are often dramatic. One such emerging process change is a new approach to controlling carbon dioxide levels in controlled atmosphere storage facilities like fruit warehouses. Current systems use nitrogen gas to dilute the carbon dioxide emitted from stored fruit that reduces fruit quality. A new system under

development and testing purges carbon dioxide gas instead and uses about one-tenth the electricity as the nitrogen dilution system.

The emergence of industry-specific processes improvements is difficult to predict. However, there are several well-understood opportunities that are noted here as examples because of their applicability in the Northwest. They include:

- Pumping system optimization in the pulp and paper industries
- Controls and process stabilization techniques in the pulp and paper industries. While all mills have process controls, the next generation of controls can provide value in process stabilization, improved quality control and assurance as well as improve up time in mills
- Advance clean-room design and system optimization techniques in electronics manufacturing plants which reduce the large HVAC loads required in clean rooms
- Refrigeration system optimization in food processing and storage industries

Developing Industrial Conservation

Successful development of industrial-sector energy efficiency depends on developing the infrastructure and relationships between program and plant staff. A network of consultants with appropriate technical expertise is needed. This expertise is available for motor management and compressed air programs. But for other measures, such as motor system optimization and industrial lighting design, where access to experienced engineers and designers is more critical, the identification and/or development of the support network will require time and effort. A mix of market transformation ventures, regional infrastructure development, and local program offerings from rebates to purchased savings will be needed to realize this source of low-cost energy efficiency potential.

COUNCIL POLICY ON FUEL SWITCHING

The appropriate role for the Council in promoting the direct use of natural gas for space and water heating has long been an issue in the region. The Council has analyzed the technical issues and the policy issues in a number of studies. The specific issues have changed somewhat over time and include: whether fuel conversions to natural gas should be considered conservation of electricity, whether incentives for electricity efficiency improvements will adversely affect natural gas markets, the cost-effectiveness and potential amount of fuel switching available to the region, whether fuel choice markets are working adequately or not, and the relative risks of price change for natural gas and electricity.

The Council policy on fuel choice has consistently been that fuel conversions, while they do reduce electricity use, are not conservation under the Northwest Power Act because they do not constitute a more efficient use of electricity. The Council has recognized, however that, if its conservation programs were to cause a reduction in the use of natural gas in favor of electricity, it would reduce the electricity savings expected from electricity conservation programs.

The Council's analysis has also recognized that in some cases it is more economically efficient to use natural gas directly for space and water heating than to use electricity generated by a gas-fired generator. However, this is very case specific and depends on a number of factors including the proximity of natural gas distribution lines, the size and structure of the house, the climate and heating requirements in the area, and the desire for air conditioning and suitability for heat pump applications. In general, although direct use of natural gas is more thermodynamically efficient (except for the case of heat pumps), it is more costly to purchase and install. Therefore, its economic advantage depends on the ability to save enough in energy costs to pay for the higher initial cost. One particularly attractive opportunity for conversion to natural gas is in homes that have natural gas space heating systems, but electric water heaters. In many of these cases, it would be cost effective for consumers to install natural gas water heaters.

The Council has not included programs in its power plans to encourage the direct use of natural gas, or the promote conversion of electric space and water heat to natural gas. This policy is consistent with the Council's view of its legal mandate. In addition, the Council's analysis has indicated that fuel choice markets are working well. Since the large electricity price increases around 1980, the electric space heating share has stopped growing in the region while the natural gas space heat share in existing homes increased from 26 to 37 percent. A survey of new residential buildings conducted in 2000 for the Northwest Energy Efficiency Alliance found that nearly all new single-family homes constructed where natural gas was available had gas-fired forced air heating systems. The survey also found an increased penetration of natural gas heating in the traditionally electric heat dominated multi-family market, especially in larger units and in Washington. Fuel conversion of existing houses to natural gas has been an active market as well, often promoted by dual fuel utilities.

The Council's policy on fuel choice is a market-based approach. The Council will leave the choice of heating fuels to individual consumers. But at the same time, the Council will work to facilitate appropriate fuel choice through information and promoting efficient pricing of electricity.

Demand Response

This is the first of the Council's power plans to treat demand response as a resource.[1] The experience with this resource is limited, and we have much to learn about the size of the resource, its costs and benefits, and the mechanisms available for its acquisition. This section defines the resource and describes some of the potential advantages and problems of the development of demand response.

WHAT IS DEMAND RESPONSE?

Demand response is a change in customers' demand for electricity corresponding to a change in the incremental cost of providing electricity. To understand the implications of this definition fully, it's important to appreciate some additional points:

1. Currently, demand response is weak or nonexistent, because most users of electricity have no indication of changes in costs of providing electricity. These costs vary considerably across hours of the day, days of the week and seasons of the year.
2. To achieve increased demand response will require the introduction of changed pricing and/or incentive programs.
3. Demand response as defined here does not include involuntary curtailment imposed on electricity users, but is a voluntary response by those users to price signals or program incentives, financial or otherwise.
4. The "incremental cost of providing electricity" includes the potential cost of new generation, transmission and distribution facilities if they are nearing their capacity for a specific time and/or place."
5. Demand response needs to correspond to the cost of involuntary curtailment if the power system can't meet all loads reliably.

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. These wholesale prices vary substantially from one hour to the next; hourly prices can vary by multiples of three to one or more over a day or two. 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

[1] According to the strict legal definitions of the Northwest Power Act, demand response is probably not a "resource" but a component of "reserves." For ease of exposition, the Plan refers to demand as a resource in the sense of the general definition of the word - "a source of supply or support."

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 hour-to-hour and day-to-day 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,[2] 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.

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

[2] 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.

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.[3] 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 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 H.

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

[3] 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.

for their *marginal* use. The "two-part" real-time prices used by Georgia Power and Duke Power provides 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.

Compared to payments for reductions, real-time prices offer significant advantages, including low transaction costs[4], 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[5] 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 (discussed in more detail in Appendix H), 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-time prices, time-of-use prices trade reduced efficiency in price signals for greater acceptability to customers and regulators, but has 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.

Any of the pricing mechanisms could be offered to customers as voluntary options, or they could be mandated for classes of customers (e.g. industrial or commercial). The voluntary option has the advantage of greater acceptability to customers, but would tend to attract customers who expect their bills to go down with little or no change in their patterns of use. The mandatory option would likely stimulate greater demand response, but customers who are faced with significant changes in their patterns of use could be expected to see such pricing as burdensome.

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

[4] Compared to the status quo of average cost pricing, all of the alternatives impose some transactions costs on consumers. In the case of real-time pricing, the consumer would experience "transactions costs" in the form of time spent monitoring frequent price variations and deciding what actions to take in response. For consumers with small electricity bills, these transactions costs could outweigh the benefits of demand response.

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

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 H.

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 (e.g. a specific production line, or a domestic water heater or furnace thermostat). 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.

There is an interesting and potentially very attractive form of direct control technology that could be available in the near future. This technology would need no intervention by a utility to reduce load, but would respond directly to stress on the power grid, indicated by grid frequency below standards. Recent work by Pacific Northwest National Laboratory and others has raised the possibility of low-cost controllers in millions of appliances, controllers that reduce loads temporarily in response to grid frequency. These controllers currently cost about $25 per appliance, but they are produced in large numbers the costs are likely to be reduced by 90 per cent or more. Appliances with such controllers represent a potentially very significant short-term "peaking" resource that could address spinning reserve requirements at very attractive cost.

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 use. 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 that 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.

ADVANTAGES OF PRICE MECHANISMS VS. 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 megawatts. Longer-term reductions of up to 1,500 megawatts 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. This means that 80 percent to 95 percent of the 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[6].

The avoided cost varies widely across the hours of the year as supply and demand for electricity is 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 has made preliminary estimates of avoided costs that are described in more detail in Appendix H. These estimates range from several hundred dollars to more than 1,000 dollars per megawatt-hour, 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/megawatt-hours 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.

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.[7] By using elasticities from the lower end of that range, modest avoided costs, and modest peak loads,[8] it was estimated that short-term demand response of at least 1,603 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 buy backs 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.

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.

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6 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.

7 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.

8 Our estimation process is described in more detail in Appendix H.

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 H.

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.

Generating Resources[1]

Generating resources available for future development in the Pacific Northwest are described in this chapter. The chapter consists of two sections. The first is a discussion of the process of producing electricity including the major power generation applications - central station generation, cogeneration and distributed generation. The second section is a discussion of the primary energy resources available to the Pacific Northwest. Here, are described the most promising generating resource options for the Northwest. Central-station electric power generating technologies are described in additional detail in Appendix I. Additional material on cogeneration and distributed generation are in Appendix J.

ELECTRIC POWER GENERATION

Electricity is produced from naturally occurring primary sources of energy. These include the fossil fuels (coal, petroleum and natural gas), geothermal energy, nuclear energy, solar radiation, energy from processes driven by solar radiation (wind, hydropower, biomass production, ocean waves, ocean thermal gradients, ocean currents and salinity gradients) and tidal energy. The energy of these primary resources can be captured, converted to electricity and delivered to the end user by means of energy conversion systems. An energy conversion system may include fuel extraction, transportation and processing; electric power generation and transmission and distribution. Fuel extraction is collection of the primary energy resource. Natural gas wells, hydroelectric dams and solar concentrators are fuel extraction technologies. Though some energy sources such as wind and water can be used directly for power generation, many require processing before use for electricity generation. Fuel processing can be relatively simple, such as chipping of wood for firing a steam-electric power plant or complex, such as the refining of petroleum into fuels for electricity generation. Electric power generation technologies take many forms, depending upon the source of energy and the application. Most are thermal-mechanical devices that capture the energy contained in heated, compressed or moving fluids, and use this energy to drive an electric power generator. Exceptions include fuel cells, solid-state devices that convert the chemical energy of hydrogen into electric power and photovoltaics, solid-state devices that convert solar insolation to electric power.

Central-station Generation

Central-station generation comprises projects constructed with the principal objective of producing electric energy at the lowest cost consistent with environmental regulations and the anticipated operational role of the plant. Central-station projects comprise the majority of Northwest generating capacity including the coal, natural gas combined-cycle and nuclear bulk power generators, hydropower and utility-scale wind projects and a scattering of simple-cycle gas turbine and reciprocating engine peaking projects that operate during periods of high loads, short supply or high power prices. While some cogeneration and distributed generation will be constructed in the region during the 20-year planning period, the bulk of new generating capacity is expected to be central-station generation because of the strong competitive advantage enjoyed by these resources. Table 5-1 lists the central-station resources thought to have the greatest

[1] All costs and prices appearing in this chapter are expressed in constant year 2000 dollars. To convert from constant year 2000 dollars prices to constant year 2004 dollar prices used in the Executive Summary, Overview, and Chapters 6 and 7, multiply by 1.0776, which is a measure of the general inflation between 2000 and 2004.

potential for serving regional load growth. These are the generating resource options forecast to have reasonably competitive costs during the period of the plan, reasonable prospects for successful development and operation and sufficient quantity to measurably impact system costs and risks. These resources were included in the portfolio analysis described in Chapter 7. Resources listed in Table 5-2 are expected to play a more limited future role because of higher cost, limited supply or limited need for the services that they provide. These resources were not considered in the portfolio analysis but nonetheless may be attractive acquisitions under the right circumstances.

Planning assumptions for the generating resources of Tables 5-1 and 5-2 are summarized in Table 5-4 at the end of this chapter and described in additional detail in Appendix I.

Table 5-1: Generating resources and technologies with major future potential (year 2000 dollars)

Resource & Technology	Applications	Resource potential	Benchmark Cost[2] ($/MWh)	Status and Earliest Northwest Service
Coal(steam electric plant)	Baseload power supply	Sufficient to meet forecast regional load growth through 2025	$43	Commercial with some technical improvement potential; 2008 (permitted projects)
Coal (gasification combined-cycle plant no carbon separation)	Baseload power supply Co-product production	Sufficient to meet forecast regional load growth through 2025	$43	Early-commercial with technical improvement potential; 2011.
Natural gas (combined-cycle gas turbine power plant)	Baseload power supply Peak power supply Cogeneration	Sufficient to meet forecast regional load growth through 2025	Baseload $46 Peak incr. $200	Commercial with technical improvement potential; 2006 (partly-complete projects)
Natural gas (gas turbine generator)	Peak power supply Cogeneration	Sufficient for typical applications	Peak $250 Standby $89/kW/yr Cogeneration $47	Commercial with technical improvement potential; 2006
Natural gas (oil sands cogeneration)	Baseload power supply Cogeneration	~2000 MW capacity per DC circuit	$43	Commercial with technical improvement potential; 2011
Wind (utility-scale wind plant)	Intermittent baseload power supply	~ 5000 MW new capacity/1500 average megawatts of energy	$35 (1st 2500 MW) $43 (2nd 2500 MW) $33 (MT local)	Commercial with technical improvement potential; 2005.

[2] Benchmark cost assumptions (except as indicated): Levelized lifecycle cost, 2010 service, Mid-Columbia location, uniform financing (20% publicly-owned utility, 40 percent investor-owned utility, 40 percent independent), medium fuel price forecast, delivery to Mid-Columbia except simple-cycle gas turbines, reciprocating engines and photovoltaics are assumed to be local. Capacity factors: Baseload coal - 80%, Baseload gas - 65%, Peaking - 5%, Standby - 0%, Wind - 30%, Cogeneration - 90%; Solar -22%. CO2 penalty, renewable energy production tax credit and green tag credits set at the means of the portfolio analysis, as applicable. Cogeneration costs based on fuel charged to power heat rate.

Table 5-2: Generating resources and technologies with moderate potential (year 2000 dollars)

Resource & Technology	Applications	Resource potential	Benchmark Cost[1] ($/MWh)	Status and Earliest Service
Wood residue (steam-electric)	Baseload power supply Cogeneration Waste disposal	1000 - 1700 aMW	$54 - 65 (w/cogen)	Commercial with technical improvement potential; 2006
Landfill gas (reciprocating engine)	Baseload power supply Waste disposal	100 - 200 aMW	$45	Commercial with technical improvement potential; 2006
Animal manure (reciprocating engine)	Baseload power supply Waste disposal	50 aMW	$56	Early-commercial with technical improvement potential; 2006
Pulping chemical recovery (steam-electric cogeneration)	Baseload power supply Cogeneration	280 aMW	$23	Commercial with technical improvement potential; 2006
Geothermal (flash steam)	Baseload power supply	Uncertain, possibly several hundred megawatts	$35[3]	Commercial technology with technical improvement potential; uncertain resource potential; 2009
Natural gas (reciprocating engine)	Peak power supply Standby power Cogeneration Distributed generation	Sufficient for listed applications	Peak $375 Standby $146/kW/yr Cogeneration $59	Commercial with some technical improvement potential; 2006
Solar (photovoltaics)	Remote power supply Distributed generation Intermittent baseload and grid support (long-term)	No effective limit	$250 (unshaped)	Commercial with technical improvement potential; 2005

[3] Benchmark cost assumptions: Levelized lifecycle cost, 2010 service, uniform financing (20% publicly-owned utility, 40 percent investor-owned utility, 40 percent independent),, delivery to the Mid-Columbia trading hub, 90 percent capacity factor, initial and replacement production and injection wells. Exclusive of possible green tag , production tax and investment credits. CO2 penalty set at the mean of the portfolio analysis.

Cogeneration

Cogeneration is the joint production of electricity and useful thermal or mechanical energy. Cogeneration involves the productive use of otherwise waste energy, thereby improving the overall energy efficiency of the production process. Production costs and environmental impacts can be lower than with than separate production of electricity and thermal products. Cogeneration comprises diverse combinations of resources, technologies and applications. Most existing installations in the Northwest are at industrial facilities and use natural gas, wood residues, biogas or spent pulping liquor as fuels. Technologies include gas turbine generators, combined-cycle power plants, steam-electric plants and reciprocating engine generator sets. The greatest potential appears to be at larger industrial and commercial installations. The smaller scale, technology and loads typical of the residential sector are not currently conducive to cogeneration cost-effectiveness. Cogeneration development is often conditioned on construction or renovation of the host facility.

Because of its generally small-scale, diversity, and unpredictable schedule, the Council did not evaluate cogeneration in the portfolio analysis. However, to provide a sense of the cost effectiveness of typical cogeneration projects, the Council assessed the cost of power from a range of proposed Northwest cogeneration projects. These projects were evaluated using proforma information supplied to the Council and the Council's forecast fuel prices and other assumptions of the portfolio analysis. The projects were as follows:

> 500 kW natural gas fired spark-ignition reciprocating engine generator with exhaust and jacket water heat recovery. Cogenerated hot water to supply a hospital hot water load. Natural gas supplied at commercial rates. Benchmark power cost [4] $73/MWh.
>
> 9 MW natural gas fired gas turbine generator with heat recovery steam generator. Cogenerated steam to supply an institutional space-conditioning load. No steam turbine generator. Natural gas supplied at commercial rates. Benchmark power cost [2] $94/MWh.
>
> 48 MW natural gas fired gas turbine generator with heat recovery steam generator. Cogenerated steam to supply an industrial process load. No steam turbine generator. Natural gas supplied at industrial rates. Benchmark power cost [2] $47/MWh.

Though these examples do not appear to be competitive with the central station generation projects of Table 5-1 solely on a wholesale power cost basis, environmental and local economic benefits, and offset transmission and distribution system costs may add sufficient value to these projects to make them desirable acquisitions.

Distributed Generation

Distributed generation is the production of power at or near electrical loads. Siting of generation at or near loads may be desirable for any of the following purposes:

[4] Benchmark cost assumptions: Levelized lifecycle cost, 2010 service, uniform financing (20% publicly-owned utility, 40 percent investor-owned utility, 40 percent independent), medium fuel price forecast. Cost as delivered to local grid including $2/MWh ancillary service charge. 90 percent capacity factor. CO2 penalty set at the mean of the portfolio analysis, as applicable. Cogeneration costs are based on fuel charged to power heat rate.

- Standby power for critical loads such as hospitals, water supply, elevators and other services. Generally required by codes.

- Standby power for high value or uninterruptible production processes.

- Regulation of voltage or frequency beyond grid standards (premium power).

- Cogeneration service to industrial or commercial thermal loads conducive to supply by cogeneration.

- Power generation using an on-site byproduct suitable for use as a fuel.

- Local voltage support during periods of high demand (grid support).

- Reliability upgrade for system served by transmission or distribution susceptible to outages.

- Alternative to the expansion of transmission or distribution system capacity.

- Service to small or remote loads where more economic than line extension.

- Peak shaving to reduce demand charges or power purchase costs during times of high prices.

Distributed generation installations tend to be smaller than central-station plants, ranging from tens of kilowatts to about 50 megawatts in capacity. The benefits of distributed generation can best be secured with resources that are flexible in location and sizing such as smaller fossil fuel technologies, technologies using transportable biomass fuels and solar photovoltaics. Established distributed generation technologies include small gas turbine generators, reciprocating engine-generators, boiler-steam turbines, and solar photovoltaics. Emerging distributed generation technologies include microturbines and fuel cells, and possibly Sterling engines. The selection of a generating technology is very dependent upon the specific distributed generation application. Technologies having low initial cost, such as reciprocating engines are favored for applications with low expected load factors such as standby power. Higher efficiency and low emissions are more important with applications having higher expected load factors such as premium power and grid support applications. Reject heat characteristics are important for selecting technologies for cogeneration applications.

Because of the typically small size of distributed generation applications, the higher unit cost and lower efficiency of the equipment compared to central-station generation, and frequently higher fuel costs, distributed generation is rarely able to compete with the energy cost of grid-supplied electricity. It is the additional value imparted by the factors listed above that can make distributed generation attractive for specific applications. Because the value of distributed generation depends upon site-specific factors not amenable to regional analysis, distributed generation options were not included in the portfolio analysis. Additional information regarding distributed generation technologies is provided in Appendix J.

Impediments to development of cogeneration and distributed generation

The diversity of distributed generation and cogeneration technologies and applications and the importance of site-specific factors in determining the cost-effectiveness of these applications precluded the inclusion of distributed generation or cogeneration in the regional portfolio analysis described in Chapter 7. However, cost-effective cogeneration and distributed generation opportunities will surface over the period of the action plan. Impediments to the development of cogeneration and distributed generation, largely institutional in nature, may preclude the development of these opportunities. A cogeneration advisory group compiled the following list of impediments to the development of cost-effective distributed generation and cogeneration. These issues are generally common to the region and the action plan includes recommendations for resolution of these issues.

- Lack of routine processes for identifying potentially cost-effective customer-side cogeneration and small-scale renewable energy resources.

- Lack of commonly accepted cost-effectiveness criteria that accurately reflect the all costs and benefits including energy and capacity value, and the value of ancillary services, avoided transmission and distribution costs and losses and environmental effects.

- Disincentives to utility acquisition of power from projects owned or operated by others. The inability of investor-owned utilities to receive a return on power purchase agreements or investment in generation owned or operated by others generation creates an economic disincentive for securing these resources.

- Lack of uniform interconnection agreements and technical standards.

- Standby tariffs not accurately and equitably reflecting the costs and benefits of customer-side generation.

- Impediments to the sale of excess customer-generated power through the utility's transmission and distribution system.

ELECTRICITY GENERATING RESOURCES

The description of electricity generating resources of this section is organized alphabetically by primary energy resource. The technologies and applications listed in Tables 5-1 and 5-2 are described in the highlighted paragraphs within the corresponding energy resource section. The section organization and identification of the resources and technologies having significant potential as follows:

Energy Resource	Major Potential	Limited Potential
Biomass		Landfill gas energy recovery Animal manure energy recovery Chemical recovery boiler cogeneration Wood residue energy recovery
Coal	Steam-electric plants Gasification combined-cycle plants	
Geothermal		Hydrothermal power plants
Hydropower		Hydropower upgrades
Natural Gas	Gas turbine generators Gas turbine combined-cycle Alberta oil sands cogeneration	Reciprocating engine-generators Small gas turbine cogeneration (App J) Microturbine cogeneration (App J) Fuel cells (App J)
Nuclear		
Ocean Currents		
Ocean Thermal		
Petroleum		
Salinity Gradient		
Solar		Remote photovoltaics
Wave		
Wind	Central-station wind plants	

Hydrogen

The last several years have witnessed increasing interest in hydrogen as an energy source. Hydrogen has a very high heat value, 61030 Btu/lb, compared to common fuels such as natural gas (23,900 Btu/lb), gasoline (~20,400 Btu/lb) and fuel oil (~19,400 Btu/lb). The high heat value of hydrogen makes it potentially attractive for the transportation of energy. Hydrogen has a further advantage in that it combusts purely to water with no formation of carbon dioxide. Finally, hydrogen is the ideal feedstock for fuel cells since fuel cells require hydrogen as fuel (hydrocarbons such as natural gas must be reformed to hydrogen and carbon dioxide when used to operate fuel cells). Operation of prime movers such as gas turbines, boilers and Sterling engines on hydrogen fuel is also possible (though not fully perfected).

Unfortunately, elemental hydrogen is not present in significant quantity at or near the Earth's surface. The potential energy role of hydrogen is therefore that of an energy storage and transport medium, analogous to liquefied natural gas, rather than a primary energy resource. Hydrogen can be produced by electrolysis of water or reformation of hydrocarbons such as coal, natural gas or petroleum. Water electrolysis could be used where the primary energy input is non-hydrocarbon in nature, such as nuclear power, hydropower, wind or solar energy. Hydrocarbon reformation could be used where the energy input is a hydrocarbon such as coal, petroleum, natural gas or biomass. Because electrolysis and chemical reformation incur energy losses, the energy contained in the hydrogen product is less than the energy input to the process. The primary energy resource must be relatively inexpensive and difficult to use otherwise for the conversion to be attractive. It is likely that the earliest production of bulk hydrogen for energy purposes would be from coal or secondary hydropower. If costs can be reduced, hydrogen may ultimately be produced by electrolysis using electricity from large-scale intermittent sources such as solar or wind power or from nuclear power plants.

Hydrogen might eventually serve as a common energy transport medium, much like today's natural gas system. Potential benefits of the so-called hydrogen economy would be reduction of end-use carbon dioxide production and provision of transportation energy from non-petroleum sources. A hydrogen-based energy system would provide great primary resource flexibility, since hydrogen can be produced using renewable, nuclear or fossil energy sources. For fossil energy feedstocks, carbon separation and sequestration could occur at the hydrogen production plant, where likely to be more economic than at the end use. In addition, the system could shape the intermittent output of solar and wind power.

Formidable engineering problems must be resolved before widespread use of hydrogen as an energy transport and storage medium. Among these are the high hydrogen pressure needed to achieve reasonable energy density, the tendency of hydrogen to embrittle common fluid containment materials, high flame temperatures that promote NOx formation and compromise engine combustion path materials, and the containment problems resulting from the small molecular structure of hydrogen. Also needed is significant improvement to the economics and reliability of fuel cells, the most promising hydrogen energy conversion device. Finally, the transformation of the existing hydrocarbon and electrical-based energy production, storage and distribution system to one based on hydrogen will be economically and institutionally challenging.

Biomass

Biomass fuels include combustible organic residues of the production and consumption of food, fiber and materials. Biomass fuels can also be obtained from dedicated energy crops, however, in the Northwest food or fiber crops typically produce a greater return on investment. For this

reason, residue fuels are likely to continue to provide the chief opportunities for the production of electricity from biomass. The chief residues available for electric power generation in the Northwest include forest residues, logging residues, mill residues, spent pulping liquor, municipal solid waste, agricultural field residues, the organic component of municipal solid waste, animal manure and landfill and wastewater treatment plant gas.

The quantity of residue material available for energy production depends on the level of economic activity, the "residue fraction" (amount of residue per unit of production producing the residue), and competing uses for the material. Production has generally declined in the forest products industry, has been stable in the other natural resources industries and has increased for municipal solid waste. Residue fractions (residue per unit output) have generally declined and competing uses have increased. An exception is forest residues. More aggressive forest health, fire control and commercial timber management could increase the availability of forest thinning residues.

Prices for biomass residues are set by the interaction of value for competing uses, cost of disposal and the cost of transportation. Fuel is the lowest value use for many of these materials, and competing uses will usually preempt the resource. For example, the pulp value of clean wood chips nearly always exceeds value as fuel. Environmental considerations generally require special disposal of residues and the cost of disposal will set a negative value on some materials. Transportation costs have an important influence on availability and delivered cost because of the low heat value and dispersed nature of many biofuels.

The estimated supply and price for the principal biomass fuels available for electric power generation in the Northwest given in Table 5-3.

Table 5-3: Estimated biofuel supply and cost (year 2000 dollars)

	Supply (TBtu/yr)	Undeveloped Potential (aMW)	Price ($/MMBtu)
Logging residue	27		$0.70 - $4.90
Forest thinning residue	39 - 125	310 - 980	$0.75
Mill residue	18	140	$0.0 - $2.05
Recovery boiler cogeneration	80	280	$0.0
Municipal solid waste/clean wood and paper fraction	64/45	365/350	($2.40 - $4.80)
Agricultural field residues	134	Not estimated	$2.40
Animal manure	--	52[5]	$0.00
Wastewater treatment plants	--	7[6]	$0.00
Landfill gas	17	175	$0.15
Hybrid cottonwood residue	3	25	$1.00
Dedicated hybrid cottonwood	Not estimated	--	$3.90

The most feasible uses of biofuels for electric power generation in the Northwest in the near-term are expected to be landfill gas energy recovery, animal manure energy recovery and chemical recovery boiler upgrades. While available in large quantities, the high cost of electric power generation using woody residues may constrain further development of this resource

[5] Energy and Environmental Analysis. Combined Heat and Power in the Pacific Northwest: Market Assessment. Prepared for Oak Ridge National Laboratory. July 2004. Dairies of 500 head, or more, poultry & swine. Excludes Montana.
[6] Ibid.

unless cogeneration opportunities are available to help reduce costs. Technical difficulties and seasonality of fuel availability are likely to preclude significant use of agricultural field residues for generation. Public opposition, high cost and established MSW disposal systems are likely to retard development of energy recovery from raw MSW, though most of the energy value of MSW can be recovered by separating the clean combustible fraction for use as fuel. A small, undeveloped potential for energy recovery exists at municipal wastewater treatment plants. Though technically feasible, the estimated cost of producing electricity from dedicated hybrid cottonwood exceeds $100/MWh, far greater than competing generating options. The wood is more valuable as a fiber crop.

Landfill Gas: Anaerobic decomposition of the organic matter in landfills produces a combustible gas consisting largely of methane and carbon dioxide. Gas production usually begins one or two years following waste placement and may last for several decades. Gas production rates vary greatly among landfills and are suppressed by water infiltration control, a normal practice for controlling leachate production. Landfill gas must be collected and combusted for safety reasons and to reduce its greenhouse gas potential[7]. Flaring is the conventional means of disposal, but electric power generation, upgrading to pipeline quality gas or use directly as a low-grade fuel are more productive uses. Most U.S. installations use reciprocating engine-generator sets, though microturbines are gaining favor in urban areas because of inherently lower NOx emissions. The undeveloped technical potential in the Northwest is estimated to be sufficient to generate about 175 average megawatts. Much of this potential is unlikely to be developed because of the high cost of electricity production at smaller landfills. The benchmark levelized cost of electricity production is about $49 per megawatt-hour. This cost is about 10 percent higher than the forecast cost of power from gas combined-cycle and other forms of bulk power production. Incentives such as the recently expanded federal production tax credit and system benefit charge funds will encourage development of this resource. Development of landfill gas energy recovery projects creates a productive use of an otherwise wasted resource and may reduce greenhouse gas production to the extent that methane losses to the atmosphere are less than that incurred with flaring[8].

Animal manure: A combustible gas largely consisting of methane and carbon dioxide is obtained by anaerobic decomposition of animal manure. This can be used as a fuel for small-scale electric power generation installations. Waste heat from power generation equipment is used to speed the digestion process. Large-scale concentrated livestock operations such as feedlots and dairy farms and areas where animal waste is a water pollution issue offer the greatest potential. The potential from larger dairies, swine and poultry operations has recently been estimated to be 52 average megawatts (excluding Montana). The benchmark cost of electricity production is $60 per megawatt-hour. While much greater than the forecast wholesale cost of power from gas combined-cycle and other bulk power sources the cost may be competitive with the retail electricity cost to the host facility. Moreover, an energy recovery system can be a component of an integrated manure disposal system to resolve environmental issues. A system may also qualify for system benefit funds or future federal production tax credits, if the scope of these is extended to biomass residues as proposed.

[7] Methane has about 21 times the greenhouse warming potential than the carbon dioxide product of its combustion.

[8] Landfill gas electricity generation is likely to lead to somewhat greater, and accelerated carbon dioxide production than flaring. However, methane losses in flaring of a couple of percent may lead to a much greater greenhouse gas impact because of the greater warming potential of methane.

Pulping Chemical Recovery: Chemical recovery boilers are used to recover the chemicals from spent pulping liquor used in chemical pulping of wood. Lignins and other combustible materials in the spent liquor create the fuel value. Recovery boilers, usually augmented by power boilers fired by wood residue, natural gas or other fuels, supply steam to the pulping process. More efficient use of the fuel is possible by producing the steam at high pressure, running it through a steam turbine generator and extracting process steam at the desired pressures. When the Fourth Power Plan was prepared, 8 of the 19 operating pulp and paper mills in the Northwest were not equipped for cogeneration in this manner. Estimates prepared for that plan indicated that an additional 280 average megawatts of electric power could be produced from installation of cogeneration equipment at recovery boilers not having such equipment. This estimate has not been updated since the Fourth Plan; however no new chemical recovery boiler cogeneration has been reported. The representative levelized cost of electricity production of a pulp and paper mill cogeneration retrofit is $24 per megawatt-hour with credit for steam. This is lower than the cost of electricity from any other new generating option. Limited capital availability and the economic conditions in the industry may account for the lack of development of this resource.

Wood Residue: Wood residues encompass forest residues, logging residues, mill residues and the clean woody fraction of municipal solid waste (urban wood waste and construction debris). Though production of logging and mill residue has declined in the Northwest over the past two decades, stabilization and possible expansion of the supply of logging and mill residue can be expected as forest recovery permits expansion of logging. The supply of forest thinnings could increase from more aggressive commercial forest management, forest health restoration efforts and wildfire control. The woody fraction of municipal solid waste is expected to increase in quantity with economic and population growth. Conventional steam-electric plants with or without cogeneration are likely to remain the chief technology for electricity generation using wood residues. The undeveloped electricity production potential of wood residue in the Northwest is potentially large, but uncertain because of the unknown future availability of forest thinnings. The Fourth Power Plan estimate was based on opening of one third of degraded National Forest lands to thinning on a 20-year cycle. This estimate yields a total wood residue supply of 132 to 218 TBtu/year. This amount would support the production of 1040 to 1720 average megawatts. The representative levelized cost of electricity production ranges from $58 to $70 per megawatt-hour, with credit for cogenerated steam. This cost is much greater than the forecast wholesale cost of power from gas combined-cycle and other forms of bulk power production and only marginally competitive with retail rates. This suggests that the resource may not be fully developed without financial incentives. These could include an extension of the federal production tax credit to biomass residues, subsidization of forest health recovery efforts or aggressive greenhouse gas control policy (wood residue is carbon dioxide neutral at sustainable harvest levels). A combination of these would likely be needed to achieve cost-effectiveness.

Coal

Coal is the solid metamorphosed residue of ancient vegetation, found in strata ranging in thickness from several inches to tens of feet, at depths of tens to hundreds of feet. Coal consists of a high percentage of carbon and lesser amounts of hydrogen, sulfur and other elements in

variable proportions. The energy content is chemical, and is recovered by combustion. Coals are classified by rank, ranging from lignite, sub-bituminous, bituminous to anthracite, corresponding to the degree of metamorphosis. Northwest coals are predominantly sub-bituminous and lignite, though bituminous coals are present in adjacent areas. A typical Powder River basin sub-bituminous coal has a moderate heat value (e.g. 8750 Btu/lb) and low sulfur (e.g. 0.4%) content. Near-surface coal is mined by removing the overburden, excavating the coal and replacing the overburden. Underground mines are used to recover deep-lying coal. Coal preparation includes crushing, sizing, washing to remove impurities and drying.

Abundant supplies of low sulfur coal are found in western North America. Production costs are low enough to permit coal to be shipped economically hundreds of miles by rail or thousands of miles by barge to power plants nearer electrical load centers. Alternatively, electricity from plants located near the mine mouth can be transmitted economically hundreds of miles to load centers. The principal coal resources available to the Northwest include the Powder River basin fields of eastern Montana and Wyoming, the East Kootenay fields of southeastern British Columbia, the Green River basin of southwestern Wyoming, the Uinta basin of northeastern Utah and northwestern Colorado and extensive deposits in Alberta. Coal could also be obtained by barge from the Quinsam mines of Vancouver Island or the Chuitna mines of Alaska. The availability of coal from fields near Centralia, Washington beyond that needed to fire the existing Centralia power plant appears insufficient to fuel additional plants.

Sufficient coal is available to the region to support all electric power needs for the 20-year planning horizon of this plan. Improvements in mining and rail haul productivity and stagnant consumption have resulted in declining production costs (in constant dollars) over the past couple of decades. Carbon dioxide control policy and overseas demand are the important uncertainties affecting future coal prices. With no improvement in coal-fired power generation technology, carbon dioxide penalties would likely depress demand and prices. However, if advanced technologies for separating carbon for sequestration become available, domestic and overseas demand and prices are likely to remain stable or even increase. Western mine mouth coal is forecast at $0.51/MMBtu and stable in year 2000 dollars in the medium case (Chapter 2).

Coal is the major source of electric power in the United States as a whole, and the second largest component (23 percent) of the western power supply. In recent decades, the economic, technical and environmental attributes of combined-cycle gas turbines eclipsed coal-fired steam-electric technology. Less than 500 megawatts of coal capacity entered service on the western grid between 1990 and 2004. However, the prospects for coal are changing. The capital cost of conventional coal steam-electric plants declined about 25% in constant dollars since the early 1990s with little or no sacrifice to electrical efficiency or reliability. This is attributable to plant performance improvements, automation and reliability improvements, equipment cost reduction, shortened construction schedule, and increased market competition. This, plus persistently high natural gas prices have reinvigorated the competition between coal and natural gas. This is evidenced in the Northwest by construction of a small 113-megawatt coal-fired plant at Hardin, Montana and plans for a 250-megawatt unit near Great Falls.

Coal-fired steam electric plants: Coal-fired power plants constructed within the next several years are likely to employ conventional steam-electric technology. This is proven technology

and plant cost, design and methods of construction and operation are well understood. Steam technology, though mature, will continue to evolve and features such as fluidized bed boilers and supercritical steam cycles are being adopted (See additional discussion in Appendix I). Public concerns regarding air emissions are likely to restrict siting to locations remote from major load centers. Transmission will therefore likely remain an important constraint on the construction of new plants. The reference plant is a 400-megawatt pulverized coal-fired unit with a subcritical steam cycle, co-located with several similar units to achieve economies of scale. The plant is assumed to be equipped with a full suite of criteria air emission[9] control equipment including activated charcoal injection for additional reduction of mercury emissions. The benchmark levelized cost of electricity production from a plant located in the Mid-Columbia area is $43 per megawatt-hour.

Coal-fired gasification combined-cycle plants: Increasing concerns regarding mercury emissions and carbon dioxide production are prompting interest in advanced coal generation technologies promising improved control of these emissions at lower cost. Under development for many years, pressurized fluidized bed combustion and coal gasification apply efficient combined-cycle technology to coal-fired generation (see additional discussion in Appendix I). This reduces fuel consumption, improves operating flexibility and lowers carbon dioxide production. Coal gasification technology offers the additional benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration and optional co-production of hydrogen, liquid fuels or other petrochemicals. The low air emissions of coal gasification plants might open siting opportunities nearer load centers.

Coal gasification combined-cycle plants were selected as representative of advanced coal power generation technologies because of incipient commercialization and potential for economical control of mercury and carbon separation. Designs with and without carbon separation were characterized. The plant without carbon separation is a 425 MW integrated coal-fired gasification combined-cycle plant using a pressurized oxygen-blown gasifier. Not included are optional hydrogen or liquid fuel co-production facilities. Though base year capital costs are 13 percent greater than the steam-electric plant because of increased complexity, this is offset by a 17 percent greater electrical efficiency and a forecast higher rate of technological improvement. The construction period, based on demonstration plant experience is somewhat longer, 48 months vs. 42 months for the conventional plant, however the increased modularity of these plants should eventually allow greater factory fabrication, improved quality and shorter lead-time. Characterized as requiring further demonstration in the draft plan, recent developments indicate that the technology is entering the early commercial stage. As discussed more fully in appendix I, vendor and architect engineer consortiums have formed to provide wraparound plant performance warranties and full design, build operate services. In addition, several utilities and independent developers have announced intent to construct coal gasification power generation capacity. The benchmark cost of electricity production from a plant located in the Mid-Columbia area is $43 per megawatt-hour. This cost is expected to decline as the technology matures.

[9] Emission controlled under the Clean Air act of 1990. These include sulfur dioxide, nitrogen oxides, particulates, hydrocarbons and carbon monoxide.

The plant with carbon separation is of the same general design as the first plant, but would be equipped for capture and compression (for pipeline transport) of 90% of its carbon dioxide production. Such a plant would likely be located in the eastern portion of the region to access geologic formations suitable for carbon sequestration. Net power output is reduced to 401 MW because of the additional energy required for carbon dioxide separation and compression. Capital costs are 22 percent higher. Though the carbon dioxide separation and compression technology assumed for this plant has been commercially proven, further testing of sustained gas turbine operation on hydrogen fuel would be required. In addition, the suitability of promising geologic formations in the Northwest for carbon sequestration remains to be demonstrated. Deep saline aquifers potentially suitable for carbon sequestration are present in eastern Montana. Further discussion of carbon sequestration is provided in Appendix K.

Geothermal

Current technology does not permit tapping the subcrustal zone that provides the ultimate source of geothermal energy. Geothermal development is presently feasible only where geologic conditions have created a near-surface heat source supporting an overlying hydrothermal circulation system. A promising resource for geothermal electricity generation requires temperatures of about 300^{o} Fahrenheit or higher, water, and fractured or highly porous rock, coincidental at depths of about 10,000 feet, or less.

Several geologic structures found in the Northwest are thought to have potential for geothermal electricity generation. Crustal spreading in the Basin and Range area of southeastern Oregon and southern Idaho has produced deep vertical faults parallel to the valleys and ranges of this geologic province. Circulation within these faults brings heated water towards the surface. Basin and Range geothermal resources are used for electric power generation in Nevada, Utah and eastern California. Recent proposals for geothermal development in southern Idaho, if successful, would be the first commercial development of Basin and Range resources in the Northwest.

The Cascade Range is an active volcanic arc derived from subduction of oceanic plates. Earlier models of Cascades geology suggested the presence of large geothermal potential, possibly as much as several hundred thousand megawatts. More recent research suggests that while local high-temperature hydrothermal systems may exist in the Cascades, geothermal potential suitable for electric power generation outside of these areas is likely to be limited or absent. Structures with geothermal potential include the magma underlying the stratovolcanos (Mounts Baker, Adams, Rainier, Hood, St. Helens, Shasta and Glacier Peak), shallow magmatic intrusions underlying the Three Sisters and Mount Lassen composite centers, low to intermediate temperature hydrothermal systems originating from the remaining portion of the Crater Lake/Mt Mazama magma chamber and intrusive bodies with known high temperature systems present at the Newberry Volcano and Glass Mountain/Medicine Lake shield complexes. The latter are the only Cascades structures offering geothermal potential not largely precluded by land use conflicts. They may be capable of supporting several hundred megawatts and possibly more of geothermal generation.

An intermediate-temperature hydrothermal system, developed for space heating exists at Klamath Falls, Oregon. Higher-temperature fluids may exist at depth. Low and intermediate

temperature thermal features of the Snake River Plain are thought to be relics of past influence of the "hot spot" now underlying Yellowstone National Park. The Island Park Caldera west of Yellowstone may hold a high-temperature resource, but lease applications were withdrawn because of concerns regarding effects on the hydrothermal features of the Park.

Because of the highly uncertain and apparently limited resource potential, geothermal power generation was not considered in the portfolio analysis of this plan. Efforts called for in the 1991 Power Plan to develop geothermal pilot projects failed to produce a viable project except at Glass Mountain where a resource had been earlier confirmed. Recent developments, including announced projects in southern Idaho, successful completion of a test well at Meager Mountain in British Columbia and extension of a federal production tax credit to geothermal projects suggest resurgence in interest in geothermal development. This plan calls on utilities to acquire renewable energy projects if cost-effective opportunities rise to encourage the development of geothermal projects.

Geothermal Power Plants: Commercially available geothermal generating technologies include dry steam, flashed steam and binary cycle power plants. Dry steam plants are used with vapor-dominated resources such as The Geysers in California. No vapor-dominated resources are known to exist in the Northwest. Flashed-steam plants or binary-cycle technologies would be used with the liquid-dominated hydrothermal resources of the Pacific Northwest. Flashed-steam plants are used with resources of about 300^{o} Fahrenheit, or greater. In these plants, the pressurized geothermal fluid is brought to the surface by means of wells and piped to a central power plant. The fluid is partially depressurized, forming steam used to drive a steam turbine generator. The residual liquid and steam condensate is reinjected into the geothermal reservoir. Binary cycle technology is used for lower temperature hydrothermal reservoirs. The geothermal liquid is brought to the surface using wells, and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine-generator, condensed and recycled to the heat exchanger. The cooled geothermal fluid is reinjected to the geothermal reservoir.

The limited cost information on geothermal plants suggests that costs have declined significantly in the past decade and a half, particularly for flash technology. Factors include increased competition, crossover oil and gas exploration and drilling technology, general improvements to plant equipment and design and more efficient engineering and construction. The example plant is a 50-megawatt double flash project located at a high quality 450^{o} F hydrothermal system in the inland Northwest within 25 miles of a suitable transmission interconnection. The benchmark cost[3] of electricity production is $35 per megawatt-hour. This cost includes initial and replacement production and injection wells. Because of limited cost information, now several years old and the considerable influence of reservoir and site conditions, this cost estimate should be regarded as highly uncertain. Also, in recent years, geothermal plants have developed nearly exclusively by independent developers. This would increase financing costs above those assumed for the benchmark cost.

Hydropower

Topographic relief and high levels of precipitation, much of which falls as snow, produce the sustained large volumes of annual runoff and vertical drop that create the great hydropower

resource of the Pacific Northwest. The theoretical hydropower potential in the Pacific Northwest has been estimated to be about 68,000 megawatts of capacity and 40,000 average megawatts of energy. Nearly 33,000 megawatts of this potential capacity has been developed at about 360 projects. Hydropower is by far the most important generating resource in the Pacific Northwest, providing about two-thirds of the generating capacity and over three quarters of electric energy on average.

Though the remaining theoretical hydropower potential of the Northwest is large, most economically and environmentally feasible sites have been developed. The remaining opportunities, though numerous, are for the most part small-scale and relatively expensive. Among these are addition of generating equipment to irrigation, flood control and other non-power water projects, incremental additions of generation to existing hydropower power projects with surplus streamflow, and a few projects at undeveloped sites. In its Fourth Plan, the Council estimated that about 480 megawatts of additional hydropower capacity is available for development at costs of 9.0 cents per kilowatt-hour, or less. This capacity could produce about 200 megawatts of energy on average. However, few projects are expected to be constructed because of the high cost of developing most of the remaining feasible sites and the complex and lengthy licensing process It appears unlikely that new hydroelectric development will be able to offset the loss of capacity and energy from expected removal of several older environmentally damaging projects.

Hydropower upgrades: More promising are potential improvements to existing hydropower projects, yielding additional capacity and energy. Many existing projects date from a time when the value of electricity was lower and equipment efficiency less than now and it is often feasible to undertake upgrades such as advanced hydro turbines, generator rewinds and spillway gate calibration and seal improvement. Even a slight improvement in equipment efficiency at a large project can yield significant energy. Earlier estimates by Bonneville suggested that over one hundred megawatts of additional energy could be secured cost-effectively through hydropower upgrades. Though numerous upgrades have since been completed, better technology and higher electricity values are likely to have extended the undeveloped potential. This plan calls on utilities to acquire renewable energy projects, including hydropower upgrades as cost-effective opportunities rise.

Natural gas

Natural gas is a naturally occurring combustible gas, predominantly methane, with lesser amounts of other light hydrocarbons, carbon dioxide, nitrogen and helium. Natural gas is found in porous geologic structures, often in association with petroleum or coal deposits. Raw natural gas is recovered by means of wells and processed to remove condensable hydrocarbons, carbon dioxide, water and impurities. The resulting product is odorized and compressed for transportation by pipeline to markets.

Though natural gas has been produced in central Montana and to a very limited extent in local areas west of the Cascades, the Pacific Northwest is not regarded as having significant future gas supplies. However, the region has excellent pipeline access to important western North American natural gas producing areas including the Western Canada Sedimentary Basin of Alberta and British Columbia, the Rocky Mountain basin of Wyoming and Colorado and the San Juan basin of New Mexico.

Low natural gas prices and development of efficient, low-cost, environmentally attractive gas-fired combined-cycle power plants led to a surge of construction early in the 1990s and again during the energy crisis of 2000 and 2001. Natural gas power plants now represent about 13 percent of Northwest generating capacity. Gas prices have since risen due to a decline in well productivity and loss of the Northwest's historic gas market advantage by expansion of pipeline transportation from Alberta to eastern markets. Interest is rising in securing access to overseas supplies of natural gas via liquified natural gas (LNG) transport and in the longer-term, LNG imports are expected play an important role in determining marginal gas prices. Over forty new LNG terminals have been proposed for North America, including one in Oregon on the lower Columbia River.

The estimated ultimate potential of gas supply areas serving the Northwest is about 22 years at current production rates. New sources of supply including "Frontier Gas" from the Alaskan North Slope and the McKenzie Delta, unconventional sources such as coal bed methane and tight sands, U.S. and Canadian offshore fields and LNG are expected to make up shortfalls and to set marginal prices in the long-term. Natural gas delivered on a firm basis to an Eastside power plant is forecast to decline on average from $5.50/MMBtu in 2005 to $4.03/MMBtu in 2015 as new sources of supply are developed. Average prices are then expected to increase slowly to $4.25/MMBtu by 2025 (year 2000 dollars). Westside prices are expected to run about 20 cents higher. Unpredictable periods of price volatility are likely to occur during this period. The natural gas price forecast is further discussed in Chapter 2.

Natural gas and petroleum are the most flexible of the primary energy resources in terms of technologies and applications. Generating technologies that can be fuelled by natural gas include steam-electric plants, gas turbine generators, gas turbine combined-cycle plants, reciprocating engine generators and fuel cells. Applications run the gamut - baseload, load following, peaking , cogeneration and distributed generation. The applications discussed here - gas turbine generators, combined-cycle plants and Alberta oil sands cogeneration - are those that might play a major role in the near to mid-term. These and other central station natural gas technologies are discussed in Appendix I. Representative natural gas cogeneration options and distributed generation applications using natural gas are discussed in Appendix J.

Natural gas-fired gas turbine generators: A gas turbine generator is a compact, modular generating plant with flexible startup and load following characteristics. A wide range of unit sizes is available, from less than 1 to greater than 170 megawatts. Gas turbine power plants (also called simple-cycle gas turbines or combustion gas turbines) are available as heavy-duty industrial machines specifically designed for stationary applications, or as "aeroderivative" machines - aircraft engines adapted to stationary applications. Sub-megawatt gas turbine generators (microturbines) are available for distributed generation applications. Low to moderate capital costs, superb operating flexibility and moderate electrical efficiency make gas turbine generators attractive for peaking and grid support applications. Cogeneration loads can be served by addition of a heat recovery steam generator. Gas turbine generators also feature highly modular construction, short construction time, compact size, low air emissions and low

water consumption[10]. Because of the ability of the hydropower system to supply short-term peaking capacity, simple-cycle gas turbines have been a somewhat minor element of the Northwest power system, comprising about 3% of generating capacity. Most are pure simple-cycle units for peaking and reserve service, and some are industrial cogeneration.

The reference simple-cycle plant consists of two 47-megawatt aeroderivative gas turbine generators. Fuel is pipeline natural gas supplied on a firm gas transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC reduction. Costs are representative of an installation at an existing gas-fired power plant site. Because of relatively low efficiency compared to combined-cycle plants, power-only simple-cycle plants would be unlikely to operate as a baseload resources. The benchmark electricity cost in peaking service (5 percent capacity factor) is $250/MWh, expensive, but comparable to other peaking generation if infrequently dispatched. Industrial-grade gas turbines are available at lower capital cost but at reduced efficiency and increased unit size. The earliest availability of new capacity is 2006.

Natural gas fired gas turbine combined-cycle power plants: Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam turbine generator. Use of the exhaust heat greatly increases the plant efficiency at little additional capital cost. Cogeneration steam loads can be served (at some loss of electricity production) by bleeding steam from the heat recovery steam generator or steam turbine. Additional generating capacity (power augmentation) can be obtained by enlarging the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing).. Because the resulting capacity increment operates at lower electrical efficiency than the base plant it is usually reserved for peaking operation. Gas-fired combined-cycle plants have been the bulk power generation resource of choice since the emergence of efficient and reliable gas-turbine generators in the early 1990s. 64 percent of the 6840 megawatts of generation constructed in the Northwest since 1990 has been gas-fired combined-cycle capacity and these plants now comprise about 10 percent of regional capacity. Reasons for this popularity include an extended period of low natural gas prices, reliable and efficient equipment, low capital costs, short lead-time, operating flexibility and low air emissions. Because of these attributes, natural gas combined-cycle plants are among the key resources considered in the development of this plan. The low carbon content of natural gas and high electrical efficiency reduces the sensitivity of these plants to possible carbon dioxide control costs. Higher natural gas costs, however, have dimmed the attractiveness of the technology.

The reference plant is comprised of two “F-class” gas turbine generators and one steam turbine generator. The baseload capacity is 540 megawatts with an additional 70 megawatts of power augmentation. Fuel is pipeline natural gas supplied on a firm gas transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for

[10] Larger amounts of water are required for cogeneration units, air inlet evaporative cooling or water injection for power augmentation or nitrogen oxide control.

CO and VOC control.[11] Condenser cooling is wet mechanical draft. The benchmark electricity cost is $46/MWh. Units in the region for which construction has been suspended could be completed by 2006. No limits were placed on the availability of additional new capacity during the planning period.

Alberta oil sands cogeneration: A special case of natural gas generation is cogeneration at the oil sands deposits of Northern Alberta. The oil sands contain the largest petroleum deposits outside the Middle East; these consist of bitumen embedded in a sandy matrix. The viscous bitumen is extracted by heating in-situ with steam, or if mined, with hot water. The extracted bitumen is processed into a synthetic crude oil. Rising oil prices have made the process economic and production is expected to expand rapidly in coming years. The steam can be produced using natural gas-fired boilers or more efficiently by cogeneration using natural gas-fired simple-cycle combustion turbines with exhaust heat recovery steam generators. Though approximately 2000 megawatts of oil sands cogeneration is in service, additional development is constrained by limited transmission access to electricity markets. A 2000-megawatt DC intertie from the oil sands region to the Celilo converter station near The Dalles has been proposed as a means of opening markets for oil sands cogeneration. The transmission could be energized as early as 2011. Preliminary estimates suggest that power from oil sands cogeneration could be delivered to the Northwest at a levelized cost of $43/MWh. While only slightly lower than the comparable cost of electricity from a new gas fired combined cycle plant in the Mid-Columbia area, the higher electrical efficiency of oil sands cogeneration may offer better protection from natural gas price volatility. Moreover, a gasification process for deriving fuel gas from oil sands processing residuals is available. This alternative fuel could further isolate oil sands cogeneration from natural gas price risk. The incremental carbon dioxide production of cogeneration is less than for stand-alone gas-fired generation, reducing the cost of possible future carbon dioxide control measures. Development of the proposed intertie, however, would present a major challenge. Transmission siting and permitting efforts in the U.S., especially for new corridors, has proven difficult. Subscription financing is proposed. While effective for financing incremental natural gas pipeline expansions, subscription for financing large-scale transmission expansions is untested. Finally, the 2000-megawatt capacity increment is likely too large for the Northwest to accept at one time. Some means of shortening commitment lead-time and phasing project output would improve prospects for development.

Nuclear

A nuclear power plant produces electricity from energy released by the controlled fission of certain isotopes of heavy elements such as uranium, thorium and plutonium. Commercial nuclear fuel is comprised of a mixture of two isotopes of natural uranium - about 3 percent fissionable U-235 and 97 percent non-fissionable, but fertile U-238. The U-238 is transmuted to fissionable Pu-239 within the reactor by absorption of a neutron. Reactors using thorium and "bred" plutonium have been developed in anticipation of eventual shortages of natural uranium. However, it appears that the industry can continue to rely on abundant supplies of natural uranium for the foreseeable future. The price of fabricated nuclear fuel is forecast at $0.40/MMBtu through period of the plan.

[11] Volatile Organic Compounds

Nuclear fuel production for light water reactors begins with concentrating the U-235 fraction of natural uranium to the desired enrichment. The enriched uranium is reacted with oxygen to produce uranium oxide. This is fabricated into pellets, which are then stacked and sealed into zirconium tubes to form a fuel rod. Fuel rods are assembled into fuel assemblies - bundles of rods arranged to accommodate neutron absorbing control rods and to facilitate removal of the heat produced by the fission process. Nuclear fuel is a highly concentrated and readily transportable form of energy, freeing nuclear power plants from fuel-related geographic constraints.

Operating nuclear units in the United States are based on light water reactor technology developed in the 1950s. Future nuclear plants are expected to use advanced designs employing passively operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost and greater reliability. Though preliminary engineering is complete, construction and operation of a demonstration project is required before the technology can be considered commercial. Electricity industry interest in participating in one or more commercial-scale demonstrations of advanced technology is increasing. But even if demonstration plant development moves ahead in the next several years, lead times are such that advanced technology is unlikely to be fully commercial until about 2015. This suggests the earliest operation of fully commercial advanced plants would be around 2020. Also needed for public acceptance of new nuclear development is a fully operational spent nuclear fuel disposal system. Though spent fuel disposal technology is available and the Yucca Mountain site is under development, the timing of commercial operation remains uncertain.

Nuclear plants could be attractive under conditions of sustained high natural gas prices and aggressive greenhouse gas control. Other factors favoring nuclear generation would be failure to develop economic means of reducing or sequestering the CO2 production of coal based generation, and difficulty expanding transmission to access new wind or coal resources. Because the earliest possible deployment of commercial units using advanced nuclear technology is late in the planning period, this technology was not further evaluated in this plan. The expected characteristics of an advanced nuclear unit are described in Appendix I.

Ocean Currents

The kinetic energy of flowing water can be used to generate electricity by water-current turbines operating on similar principals to wind turbines. Conceptual designs and prototype machines have been developed and arrays of current turbines have been recently proposed for New York City's East River and San Francisco's Golden Gate. Turbine energy yield is very sensitive to current velocity and little electrical potential is available from the weak and ill-defined currents off the Northwest coast and in the Strait of Juan de Fuca. Tidal currents of 3 to 8 knots occur locally in Puget Sound and estuaries along the Oregon and Washington coast. Because these velocities are attained for only an hour or two on the run of the tides and are unlikely to provide an economic source of energy in the foreseeable future.

Ocean Thermal Gradients

An ocean thermal energy conversion (OTEC) power plant extracts energy from the temperature difference that may exist between surface waters and waters at depths of several thousand feet.

Megawatt-scale OTEC technology has been demonstrated in Japan and Hawaii, but the technology is inefficient (2 - 3%) and requires a temperature differential of about 20^{o} C (36^{o}F). Temperature differentials of this magnitude are limited to tropical regions extending to 25 to 30 degrees of latitude. Ocean thermal temperature differentials in the Northwest range from 0 to 12^{o}C (0 - 20^{o}F) precluding operation of OTEC technology.

Petroleum

Petroleum is comprised of liquid hydrocarbon compounds thought to originate from the buried remains of marine organisms. These materials migrated through porous geologic formations and accumulated below folded impermeable sedimentary formations. Crude petroleum is extracted by means of wells and refined using distillation, cracking, hydrotreating and other processes into a wide variety of products. Among these are propane, distillate and residual fuel oils, which can be used as fuels for electric power generation.

Petroleum fuels are universally available at prices largely determined by the global market. Fuel oil prices are expected to decline from current highs and over the term of this plan, upward pressure on petroleum fuel prices from increasing demand in developing countries should be offset by relatively low and constant production costs. The prices of industrial distillate and residual fuel oils are forecast to be $4.43 and $7.69/MMBtu, respectively, in 2005 (year 2000 dollars). In the medium case, these prices are forecast to decline through 2010 then stabilize on average with likely periods of short-term volatility. Residual and distillate prices in 2025 are forecast to be $3.99 and $7.12/MMBtu, respectively (Chapter 2). . In general, the cost of petroleum-derived fuels is too high for bulk electric power generation. Fuel oil is used as a backup fuel, for peaking or emergency service power plants and for power generation in remote areas.

Salinity Gradients

Energy is released when fresh and saline water area mixed. Conceptually, the energy potential created by fresh water streams discharging to salt water bodies could be captured and converted to electricity. Concepts that have been advanced for the generation of electric power from salinity gradients include osmotic hydro turbines, dilytic batteries, vapor pressure turbines and polymeric salinity gradient engines. These technologies are in their infancy, and it is not clear that current concepts would be able to operate off the natural salinity gradient between fresh water and seawater. Although the theoretical resource potential in the Northwest is substantial, many years of research, development and demonstration would be required to bring these technologies to commercial availability.

Solar

The amount of solar radiation reaching the ground and available for conversion into electricity is a function of latitude, atmospheric conditions and local shading. The resource potential in the Northwest is greater east of the Cascades, with less annual cloud cover. Latitude and shading are influential and the most promising areas lie in the southern portion of the region, in open and flat terrain. The best areas are the inter-mountain basins of south-central and southeastern Oregon and the Snake River plateau of southern Idaho. On an annual average, these areas receive about 75 percent of the insolation received in Barstow, California, one of the best U.S. sites.

The strong summer seasonality of the Northwest solar resource suggests that while the solar resource has potential for serving local summer-peaking loads, such as irrigation and air conditioning, it is less suitable for serving more general regional loads. There have been no comprehensive studies of site suitability for development, though in theory, there is sufficient solar resource to support all regional electrical requirements.

Solar energy can be converted to electricity using solar thermal technologies or photovoltaics. Solar thermal technologies remain very costly and are potentially suited to bulk power generation. The most promising application of solar power during the near-term appears to be small-scale photovoltaic installations servicing to small loads isolated from the grid. Though flat in recent years, the reduction in photovoltaic costs over the past several decades has been rapid compared to other power generation technologies.

Photovoltaics: Photovoltaics is solid-state conversion of sunlight to electricity. The technology is commercially established and widely employed to serve small remote loads for which it is too costly to extend grid service. Power output is intermittent and battery storage or auxiliary power is required for loads demanding a constant supply. Because no combustion or other chemical reactions are involved, photovoltaic power production is emission free. No water is consumed other than for periodic cleaning. Costs are presently too high for economic grid-connected electricity production. A representative cost of unshaped busbar power from rooftop grid-connected photovoltaic systems is currently $250 megawatt-hour. If costs continue to decline at the average historical rate, by 2025 central station plants might produce unshaped power at the busbar for $45 per megawatt-hour; a cost competitive with other central station technologies. However, photovoltaic cost reduction has stagnated in recent years and technical breakthroughs may be required to achieve the cost reductions required for large-scale deployment. Because of the prospects of a continuing high differential between photovoltaic electricity costs and market value, there appears little that the region can do to promote cost reductions for this globally traded product beyond seeking out near-economic niche applications and to encourage federal research.

Tidal Energy

Tidal energy originates from the loss of the earth's rotational momentum due to drag induced by gravitational attraction of the moon and other extraterrestrial objects. Tidal energy can be captured and converted to electricity by means of hydroelectric "barrages" constructed across natural estuaries. These admit water on the rising tide and discharge water through hydroturbines on the ebb. The key requirement is a large mean tidal range, preferably 20 feet or more. Suitable sites with tides of this magnitude occur only in a few places worldwide where the landform amplifies the tidal range. Tidal hydroelectric plants have been developed in some of these locations. Environmental considerations aside, the development of economic tidal hydroelectric plants in the Northwest appears to be precluded by insufficient tidal range. Mean tidal ranges in the Pacific Northwest are between 4.5 and 10.5 feet, with the greatest mean tides found in bays and inlets of southern Puget Sound.

Wave Energy

Recently proposed West Coast demonstration projects have sparked interest in ocean wave electricity generation. Waves are produced by the action of wind blowing over water. The wave energy of the mid- and North Pacific coasts is the best of any coastal area of the United States,

with estimated average wave power at near-shore locations ranging from six to nine kilowatts per meter of wave crest. Offshore, the estimated power is 37 to 38 kilowatts per meter of wave crest. The theoretical wave power potential of the Washington and Oregon ocean coast is approximately 3400 - 5100 megawatts for near-shore sites and 21,000 megawatts for offshore sites. Wave power devices are expected to have an efficiency of at least 12 percent; suggesting a technical potential of 400 to 2500 megawatts. Only a portion of this potential is likely to be available because of navigational, aesthetic or ecological concerns, and the need to maintain clearance between wave power units. Wave power in the Northwest is winter peaking with a high seasonal variation of a factor of 20. Wave energy technology is in its infancy. A diversity of conceptual designs have been proposed and several prototypes and demonstration projects constructed. Though it is unlikely that a commercially viable technology will become widespread during the period of this plan, the recently proposed West Coast demonstration projects suggest that the process of winnowing and refining technologies may accelerate.

Wind

Winds blow everywhere and a few very windy days annually may earn a site a windy reputation, but only areas with sustained strong winds averaging roughly 15 mph, or more are suitable for electric power generation. A good wind resource area will have smooth topography and low vegetation to minimize turbulence, sufficient developable area to achieve economies of scale, daily and seasonal wind characteristics coincident to electrical loads, nearby transmission, complementary land use and absence of sensitive species and habitat. Because of the low capacity factors typical of wind generation, transmission of unshaped wind energy is expensive. Interconnection distance and distance to shaping resources are very important.

Because of complex topography and land use limitations, only localized areas of the Northwest are potentially suitable for windpower development. However, excellent sites are found within the region. Wind resource areas in the Northwest include coastal sites with strong but irregular storm driven winter winds and summertime northwesterly winds. Areas lying east of gaps in the Cascade and Rocky mountain ranges receive concentrated prevailing westerly winds, wintertime northerly winds and winds generated by east-west pressure differentials. The Stateline area east of the Columbia River Gorge, Kittitas County in Washington and the Blackfoot area of north central Montana are of this type. A third type of regional wind resource area is found on the north-south ridges of the Basin and Range geologic region of southeastern Oregon and southern Idaho.

Intensive prospecting and monitoring are required to confirm the potential of a wind resource area. Though much wind resource information is proprietary, the results of early resource assessment efforts of the Bonneville Power Administration, the U.S. Department of Energy and the State of Montana, recently compiled resource maps based on computer modeling plus a the locations of existing and announced wind projects give a sense of the location and characteristics of prime Northwest wind resource areas. Educated guesses by members of the Council's Generating Resource Advisory Committee are that several thousand megawatts of developable potential occur within feasible interconnection distance of existing transmission. The magnitude of this estimate is supported by the 3600 megawatts aggregate capacity of undeveloped wind projects announced over the past several years. For the base case analyses of this plan we assume 5000 megawatts of developable potential west of the Continental Divide.

Central-station wind plant: The reference plant is a 100-megawatt wind plant located in a prime wind resource area within 10 to 20 miles of an existing substation. The plant would include 50 to 100 utility-scale wind machines. Sites west of the Rocky Mountains classified into two classes (blocks) of 2500 megawatts each. The first block is assumed to yield a capacity factor of 30 percent and incur shaping costs of $4.55/MWh. The benchmark cost for shaped power delivered to a customer on the main grid is $35/MWh in 2010. The second block is of lesser quality, yielding a capacity factor of 28 percent and shaping costs of $9.75/MWh. The benchmark cost for shaped power delivered to a customer on the main grid is $43/MWh in 2010. Sites east of the Rocky Mountains are assumed to yield a capacity factor of 36 percent and a shaping cost of $9.75/MWh. The benchmark cost of shaped power, delivered locally, is $33/MWh. These latter sites are electrically isolated from the regional load centers and would require construction of long-distance transmission to access outside markets.

Table 5-4: Generating resource planning assumptions

	Unit Size (MW)	Capital ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh) (base/CHP)	Technology Improvement (cost/heat rate %/yr)	Operat-ing Availab ility (%)	Shaping ($/ MWh)	Fixed Trans-mission ($/kW/yr)	Trans-mission Loss (%)	Dvl/Cnst Schedule (months)	Dvl/ Cnst Cash flow (%)
Coal steam-electric	400	$1243	$40	$1.75	9550	0.1%/-0.3%	84%	--	$15	1.9%	36/42	3%/97%
Coal gasification combined-cycle (no CO2 separation)	425	$1400	$45	$1.50	7915	-0.5%/-0.5% (post-2011)	83%	--	$15	1.9%	36/48	2%/98%
Coal gasification combined-cycle (CO2 separation)	401	$1800	$53	$1.60	9290	-0.5%/-0.5% (post-2011)	83%	--	$15	1.9%	36/48	2%/98%
Geothermal flash steam	50	$1830	$96	Inc. in fixed	9300	-1.1%	92%	--	$15	1.9%	36/24	16%/84 %
Natural gas-fired gas turbine generator	94	$600	$8	$8.00	9955	-0.5%/-0.5%	94%	--	$15	1.9%	12/12	3%/97%
Natural gas-fired combined-cycle	610	$525	$8	$2.80	7030 (base) 9500 (peak)	-0.5%/-0.5%	90%	--	$15	1.9%	24/24	4%/96%
Oil sands cogeneration	2000	$1071	Inc. in Variable	$2.80	5800	-0.5%/-0.5%	95%	--	$9	7.7%	48/36	5%/95%
Advanced nuclear power plants	1100	$1450	$40	$1.00	9600	0%/0%	88%	--	$15	1.9%	36/60	8%/92%
Wood residue steam-electric	25	$2000	$80	$9.00	14,500/4500	0%/0%	90%	--	$15	1.9%	24/24	5%/95%
Landfill gas energy recovery	1	$1360	$125	$1.00	11,100	0%/0%	80%	--	$15	1.9%	12/12	5%/95%
Animal manure energy recovery	0.5	$3100	$67	Inc. in fixed	11,100	0%/0%	90%	--	$15	1.9%	24/12	5%/95%
Chemical recovery boiler cogeneration	25	$680	Inc. in variable	$14.00	4500 (CHP)	0%/0%	90%	--	$15	1.9%	24/12	5%/95%
Photovoltaics	0.002	$7000	$32	$0.00	--	-8%		$4	--	--	<12	100%

	Unit Size (MW)	Capital ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh) (base/CHP)	Technology Improvement (cost/heat rate %/yr)	Operat-ing Availab ility (%)	Shaping ($/ MWh)	Fixed Trans-mission ($/kW/yr)	Trans-mission Loss (%)	Dvl/Cnst Schedule (months)	Dvl/ Cnst Cash flow (%)
Wind power[12]	100	$1010	$20	$1.00	--	-2%	B1 30% B2 28% B3 36%	$4.55 $9.75 $9.75	$20	1.9%	24/12	8%/92%

[12] Wind power is divided into three blocks. Block 1 (B1) represents better quality Washington, Oregon, Idaho and western Montana resources. Block 2 (B2) represents lesser quality, yet promising Washington, Oregon, Idaho and western Montana resources. Block 3 (B3) represents better quality resources of central and eastern Montana.

Risk Assessment & Management

This chapter presents the Council's approach to addressing uncertainty and managing risk. After reviewing the reasons for addressing uncertainty in the Council's Fifth Power Plan, it defines key terms and describes the analyses' principal sources of uncertainties. It describes how the studies evaluated the performance of resource plans under uncertainty, including their associated risk. The chapter introduces concepts that assist with the evaluation of cost-risk tradeoff, such as the "feasibility space" of plans and feasibility space's efficient frontier. It also describes the computer simulations the Council used to quantify plan performance and to construct the feasibility space. Most of the discussion of the computer model and the results of the simulations and analysis, however, appear in the next chapter. This chapter then briefly examines alternative measures of performance and risk and compares these to the selected approach.

In the last sections of this chapter, some background on and description of risk mitigation measures appears. Examples of risk mitigation measures are options to construct new power plants or implement voluntary load-curtailment programs. These sections emphasize the importance of planning flexibility in risk mitigation. Planning flexibility refers to the value of a planning option's ability to inexpensively and effectively respond to changing circumstances.

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 are there ways to assure its development?
- 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 decisions about resource additions?
- How does transmission improve system reliability?
- What is the possible impact of global climate change on the power plan?

The evaluation of each of these issues depends on the decision maker's view of risk and uncertainty. For example, demand response is forthcoming if incentives exceed around $100-$150 per megawatt-hour. Even though demand response programs are relatively inexpensive to maintain, most forecasts of wholesale electric power prices rarely, if ever, exceed this value. The energy crisis of 2000-2001, however, demonstrated 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, load uncertainty, fuel price uncertainty, and hydro generation variability figured prominently in the conclusions of the plan. Those plans incorporated gas and coal price excursions in forecasts and sensitivity analyses. They also considered capability to export and

import various amounts of power to and from outside the region. Since the first power plan, the Council has analyzed the value of shorter lead times and rapid implementation of conservation and renewables. The Council has also valued "optioning" generating resources – carrying out pre-construction activities and then, if necessary, delaying construction until conditions favor going ahead.

In this plan, the Council further integrates risk assessment and management into its analysis and extends the assessment of risks to such issues as electricity market price uncertainty, aluminum price uncertainty, and emission control cost uncertainty. The analysis includes periods up to a few years when power and fuel prices, as well as other sources of uncertainty, deviate significantly from equilibrium levels. The study abandons the assumption of perfect foresight to better assess the value of risk mitigation.

DEFINITIONS

The following are terms used throughout the power plan.

- **Uncertainty** is a measurement of the quality of information about an event or outcome. Some future events are uncertain, but there is a significant amount of information about their likelihood. For example, the total annual flow at Bonneville Dam in 2010 is uncertain, but 61 years of historical records provide information about the distribution of outcomes. Other future events are less certain, like prices of natural gas and electricity. Theory and experience are informative to some degree, but expectations can be confounded. For others, there is very little information to go on. For example, there is almost no objective basis for determining the magnitude of any carbon tax in 2010. Future events therefore lie along a spectrum of varying degrees of uncertainty.

- **Futures** are uncontrollable events or circumstances. Futures are combinations of sources 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 adopted plan.

- **Plans** are future actions that are controllable. Plans include preparations to construct new power plants and the implementation of demand-side strategies or mechanisms. Power plant preparations include siting and licensing for specific construction start dates and quantities for each type of plant.. Different resources also provide differing amounts of planning and operating flexibility. These are inherent attributes of each plan.

- A **Scenario** is a plan considered under a specific future. The cost of a fixed plan under multiple futures provides the basis for cost distributions used in this study. Consequently, the costs of scenarios are fundamental to the study of uncertainty and risk.

- **Risk** is a measure of bad outcomes associated with a given plan. If the primary outcome of a study is the net present value cost over a study period, 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 risk. A dispatchable power plant may protect a power system from high costs when electricity prices fall, because generation and fuel cost are curtailable. A demand-side strategy can protect a power system from fuel price risk and electricity market risk.

UNCERTAINTIES

What are some of the primary sources of uncertainty, 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?

The power plan addresses the following sources of risk:

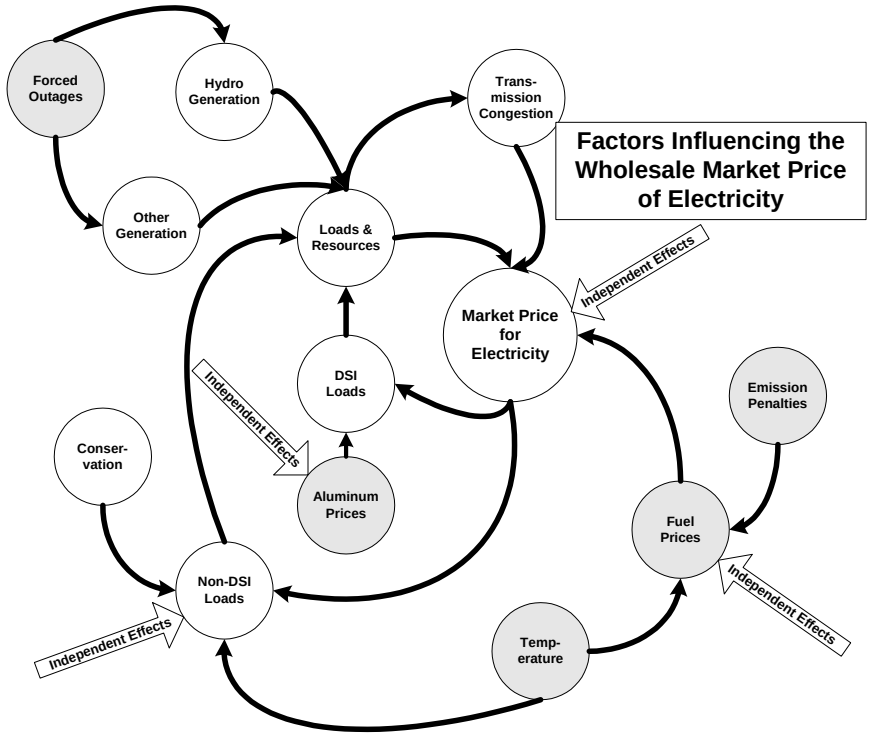


Figure 6-1: Factors Influencing the Wholesale Electricity Price

- **Wholesale Power Prices** – Many forecasters use long-term equilibrium models such as Aurora® to estimate future electric power prices. 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, inactivity due to prior surplus, overreaction to prior shortages, and other factors. 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. Because it is very difficult for an individual utility to exactly match loads and its own resources at all times, virtually all utilities participate in the wholesale market, directly or indirectly, as buyers and as sellers. This is particularly so when the region's primary source of generation, hydroelectricity, is highly variable from month to month and year to year.

To capture these effects, simulation models must vary electricity prices with hydropower availability, loads, and natural gas prices. The Council's portfolio model, described later in this chapter and in the next chapter, incorporates correlations among those factors. In addition, market prices must 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 will be reduced until generation equals loads plus export capability. Similarly, if generation is inadequate to meet requirements, given the region's import capability, prices will increase until the situation is resolved, i.e., loads are reduced or the price induces sufficient generation.

Finally, electricity prices also exhibit substantial random variations due to conditions in other parts of the interconnected West and other factors that are not explicitly considered. These other factors include, for example, regulatory and legislative innovations and the introduction of new generation technologies. Figure 6-2 shows a sample of electricity price futures from the portfolio model.

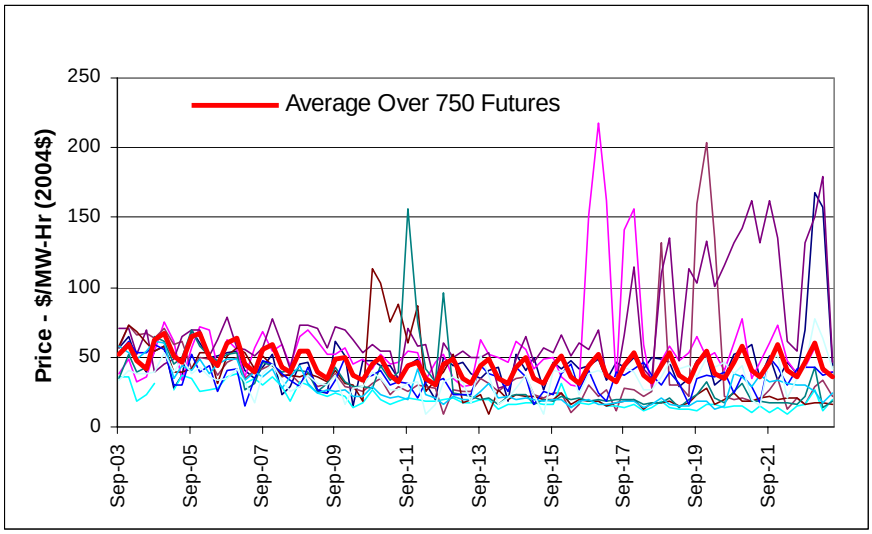


Figure 6-2: Electricity Price Futures

The Council contracted 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 results of these analyses. These analyses form the basis for the Council's representations of price paths, uncertainties, volatilities, and correlations. The results of these analyses are included in Appendix P.

- **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 range for non-aluminum loads serves as a basis for the characterization of uncertain load trends. The expected load and the long-term load probability distribution are consistent with the forecast range. However, additional variations in load are added in the portfolio analysis to reflect seasonal and hourly patterns of load as well as excursions for weather variations and business cycles. Figure 6-3 displays a sample of load futures from the portfolio model simulations compared to the trend forecast range.

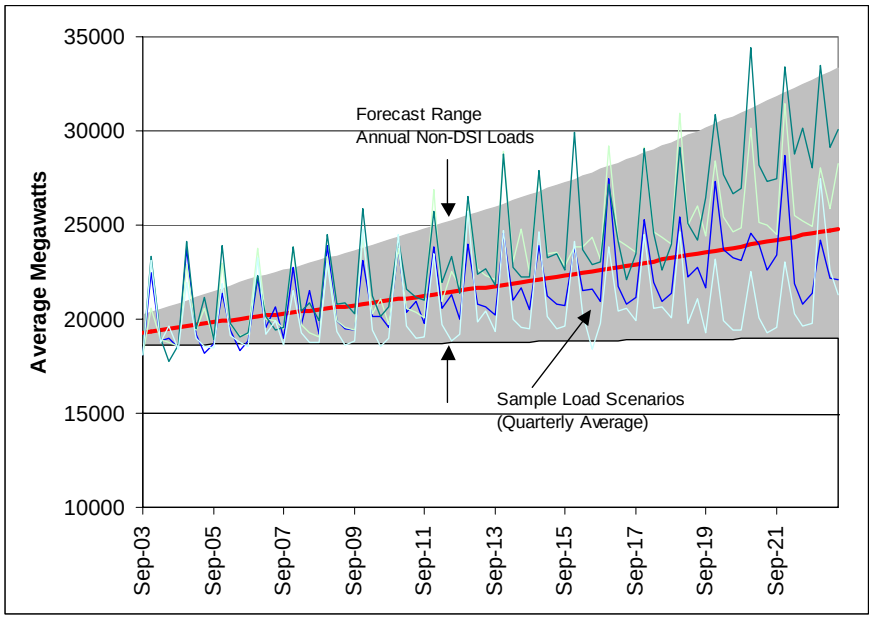


Figure 6-3: Load Futures

- **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. The portfolio model captures the relationship among varying aluminum prices, electricity prices, and aluminum plant operation. In addition, the analysis considers the likelihood of permanent aluminum plant closure if a plant is out of operation for an extended period. Given the future electricity and aluminum price trends and variations and absent some policy intervention, the portfolio model results show a 80 percent likelihood of all aluminum plants closing during the forecast period.

- **Fuel Prices** - The basis for uncertain natural gas price trends is the Council's fuel price forecast range including estimates of uncertainty in the expected annual price. In addition to uncertainty in long-term trends in fuel prices, the modeling representation

uses seasonal patterns and brief excursions from trends. These excursions may last from six months to four years and then recover back toward the trend path. The duration of the excursion and the duration of the price recovery are both functions of the size of the excursion. Figure 6-4 illustrates some natural gas price futures from the portfolio model simulations (2004$).

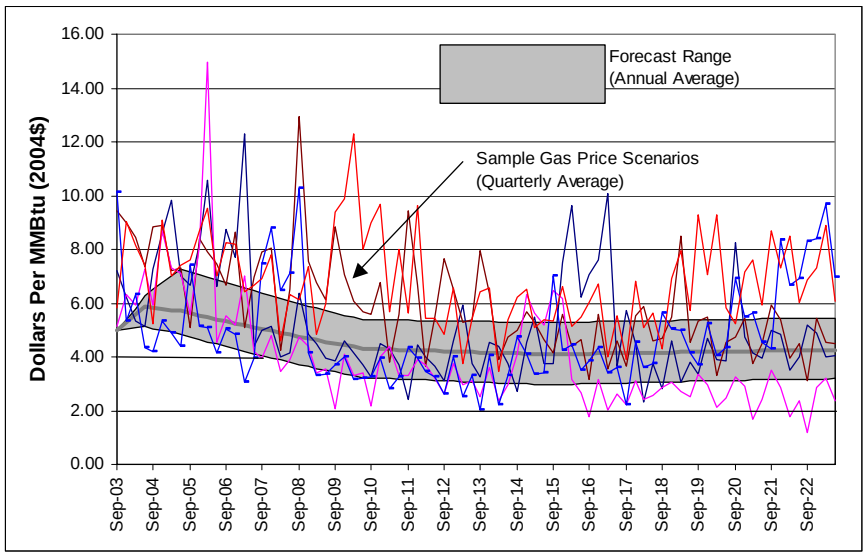


Figure 6-4: Gas Price Futures

- **Hydro generation** - A 50-year history of streamflows and generation provide the basis for hydro generation in the model. The hydro generation reflects constraints associated with the NOAA Fisheries 2000 biological opinion. The modeling assumes a decline of 300 average megawatts over the 20-year study period to capture relicensing losses, additional water withdrawals, the retirement of inefficient hydro generation units, and other factors that might lead to capability reduction. Hydro generation modeling did not reflect generation changes due to any climate change, because study results are too preliminary. Appendix N addresses work to understand any climate change impact on the hydroelectric system.

- **Climate Change -** A significant proportion of scientific opinion holds that the earth is warming due to atmospheric accumulation of greenhouse gasses. The increasing atmospheric concentration of these gasses appears to result largely from combustion of fossil fuels. Significant uncertainties remain, however, regarding the rate and ultimate magnitude of warming and its effects. The possible beneficial aspects to warming appear outweighed by adverse effects. A number of industrialized nations are taking action to limit the production of carbon dioxide and other greenhouse gasses. Within the United States, a number of states, including Washington and Oregon, have initiated efforts to control carbon dioxide production. It appears that the United States could eventually enact federal climate change policy involving carbon dioxide control. Further discussion of climate change policy appears in Appendix M

  Because it is unlikely that reduction in carbon dioxide production can be achieved

without cost, future climate control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to be the most cost-effective approach to CO_2 control. The model, however, uses a fuel carbon content tax as a proxy for the cost of carbon dioxide control, whatever the means of implementation. The effect on existing power plant generation and the economic value of new generation would be representative of any type of effort to control CO_2 production using carbon-proportional constraints.

In the model, a carbon tax can arise in any election year. The probability of such a tax being enacted in at some time during the forecast period is sixty-seven percent. If enacted, the value for the carbon tax is selected from a uniform distribution between zero and $15 per ton if it is enacted between 2008 and 2016; and between zero and $30 per ton if enacted thereafter (2004$). Additional sensitivities are also considered.

- **Renewable energy production incentives** - Originally enacted as part of the 1992 Energy Policy Act to commercialize wind and certain biomass technologies, the production tax credit and its companion Renewable Energy Production Incentive have been repeatedly renewed and extended. These production tax credits (PTCs) have amounted to approximately $13 per megawatt hour on a levelized basis (2004$). The incentive expired in at the end of 2003 but, in September 2004, was extended to the end of 2005, retroactive to the beginning of 2004. In addition, in October, the scope of qualifying facilities was extended to include all forms of "open loop" biomass (bioresidues), geothermal, solar and certain other renewable resources that did not previously qualify. Though the amount and duration of the credit for wind remained as earlier, the credit for open loop biomass and other newly qualifying resources is half the amount available for wind and limited to the first five years of project operation. The longer-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as the above-market cost of qualifying resources are reduced. Moreover, federal budget constraints may eventually force reduction or termination of the incentives. In the model, two events influence PTC value over the study period.

  The first event is termination due to cost-competitiveness. There is a small probability the PTC could disappear immediately, if congress decided renewable energy technology is sufficiently competitive and funds are needed elsewhere. The likelihood of termination peaks in the model when the fully allocated cost of wind approaches that of a combined cycle power plant around 2016. The probability falls to zero when the wind energy-cost forecast declines to 30 mills/kWh in 2034 (2004$). That is, there is never a modeling future where a PTC extends beyond 2034.

  The second event that modifies the PTC in the Council's model is the advent of a carbon penalty. This event is related to the first, in that a carbon penalty would make renewables that do not emit carbon more competitive relative to those generation technologies that do. A CO_2 tax of less than about $15 per short ton of CO_2, however, would not completely offset the support of the PTC. For this reason, the value of the PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the

carbon penalty. If the carbon penalty is below half the initial value ($9.90 per megawatt hour in 2004$) of the PTC, the full value of the PTC remains[1]. If the carbon penalty exceeds the value of the PTC by one-half, the PTC disappears. Between 50 percent and 150 percent of the PTC value, the remaining PTC falls dollar for dollar with the increase in carbon penalty, so that the sum of the competitive assistance from PTC and the carbon penalty is constant at 150 percent of the initial PTC value over that range.

- **Green tags** - Power from renewable energy projects currently commands a market premium - a reflection of the perceived environmental, sustainability, and risk mitigation value of renewable energy resources. Driving the premium are above-market prices paid by utility customers for "green" power products, above-market prices paid for renewable energy components of utility supply portfolios and above-market prices for renewable acquisitions to meet requirements of renewable portfolio standards and system benefit charges. Tag value varies by resource and is reported to be between $3 to $4 per megawatt-hour for wind power, at present.

  In the model, green tag value can start the study period any where between $3 and $4 per megawatt-hour with equal likelihood (2004$). By the end of the study, the value can be anywhere between $1 and $8 per megawatt-hour (2004$). A straight line between the beginning and ending values determines the value for intervening periods. Consequently, green tag value averages 3.50 at the beginning of the study and averages $4.50 at the end of the study. Uncertainty in the value increases over time. This value is unaffected by events such as the emergence of a carbon penalty or the termination of the production tax credit.

- **Windpower shaping costs** - Windpower shaping costs are reported to range from $3-$8 per megawatt hour, lower than expected several years ago. The model uses deterministic shaping costs: $5.02 per megawatt hour for the first 2,500 megawatts of wind capacity and $10.76 per megawatt hour thereafter (2004$).

- **Other Emission Costs** - Power plant costs include the cost of the best available control technology required to meet current air emission requirements. The costs for coal-fired power plants also assume additional mercury control in anticipation of regulations currently under consideration by the Environmental Protection Agency.

- **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

[1] The conversion of carbon penalty ($/US short ton of CO_2) to $/MWh is achieved with a conversion ratio 1.28 #CO_2/kWh. This conversion ratio corresponds to a gas turbine with a heat rate of 9000 BTU/kWh.

compelling. The Council uses models to screen plans, not as a substitute for experience and judgment.

Sensitivity analyses around the distributions for the uncertainties provide another check on the modeling work. The resource plan produced by Council staff incorporates distributions of forecasts prepared or reviewed by experts in an open forum. Although "uncertainty about uncertainty" does not make sense for a single decision maker, there nevertheless will be a diversity of opinion among decision makers about the uncertainty of specific forecasts.

The Council's model does not explicitly treat other sources of uncertainty, such as changes in technology and policy, fish and wildlife programs, and the transmission system. Appendix P describes these sources of uncertainty and any treatment in this analysis.

OBJECTIVES AND MEASURES OF RISK

How are the costs and benefits of plans determined? How is risk measured? Whose assessment of risk should be used?

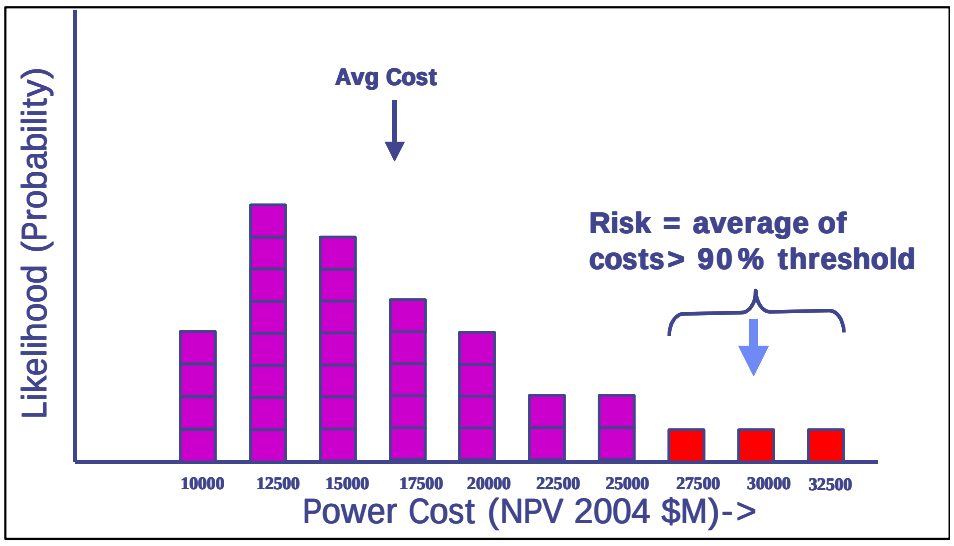
The Council's approach to resource planning is called "risk-constrained least-cost planning." Given any level of risk tolerance, there should be a least-cost way to achieve that level of risk protection. The purpose of the Council's analysis is to define those plans that do just that.

Given a particular future, the 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 operation and maintenance (O&M), certain short-term purchases, and fixed costs associated with future capital investment and O&M. The present value calculation discounts future costs to constant 2004 dollars using a real discount rate of four percent.[2] 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.

If the future were certain, net present value system cost would be the only measure of a plan's performance. Because the future is uncertain, however, it is necessary to evaluate plans over a large number of possible futures. Complete characterization of the plan under uncertainty would require capturing the distribution of outcomes over all futures, as illustrated in Figure 6-5 below. Each box in Figure 6-5 represents the net present value cost for a scenario sorted into "bins." Each bin is a narrow range of net present value total system costs. A scenario is a plan under one particular future.

Because a simulation typically uses 750 futures, the resulting distributions can be complicated. Representative statistics make manageable the task of capturing the nature of a complex distribution. The *expected* net present value total system cost captures the central tendency of the distribution. The expected net present value is the average of net present value total system costs, where the average is frequency weighted over futures. This plan will often use the shorthand expression, "average cost of the plan." The average cost is identified in Figure 6-5.

[2] See Appendix L.



Expected net present value cost, however, does not give 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 "TailVaR$_{90}$" was chosen. This choice of risk measure and its comparison with other risk measures appears in Appendix P. Very briefly, TailVaR$_{90}$ is the average value for the worst 10 percent of outcomes. It belongs to the class of "coherent" risk measures that possess mathematical properties 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).

ASSESSING PLAN PERFORMANCE AND IDENTIFYING OPTIMAL PLANS

The primary tool for identifying risk-constrained, least-cost plans is an analytical system with three components. The first component is Olivia, which creates an Excel® workbook portfolio model. With minor refinements, an early version of this workbook model has served as the regional model. Olivia is part of an effort that extends beyond the fifth regional power plan. The vision is to provide data and tools like Olivia to others -- such as utilities and public utility commissions -- to help them perform their own risk analysis using concepts and techniques developed by the Council.

The second component is the Excel workbook model itself, "the portfolio model." This workbook model is the calculation engine. It estimates costs of generation, of purchases and sales of wholesale power, and of capacity expansion over the 20-year study period. An Excel add-in runs a Monte Carlo simulation of the scenarios, with each game corresponding to a future.[3] This simulation gives rise to the cost distribution illustrated in Figure 6-5 for each plan.

Figure 6-6 illustrates the kind of calculation that the portfolio model makes in a specific scenario. It shows energy use resulting from a plan over a two-year time period for the fixed future. The future defines hydro generation, loads, gas prices, and so forth in each hour. Given these

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

circumstances, existing and future resources in the plan generate power, largely in response to wholesale electricity prices. Because generation rarely exactly matches load, power is purchased from or sold into the wholesale market. The model sums costs and revenues in each hour, adds any future fixed costs for existing and new generation or capital costs for new generation and conservation, and discounts the dollars to the beginning of the study. Of course, the portfolio model uses 20 years of costs, not two years, but the process is identical.

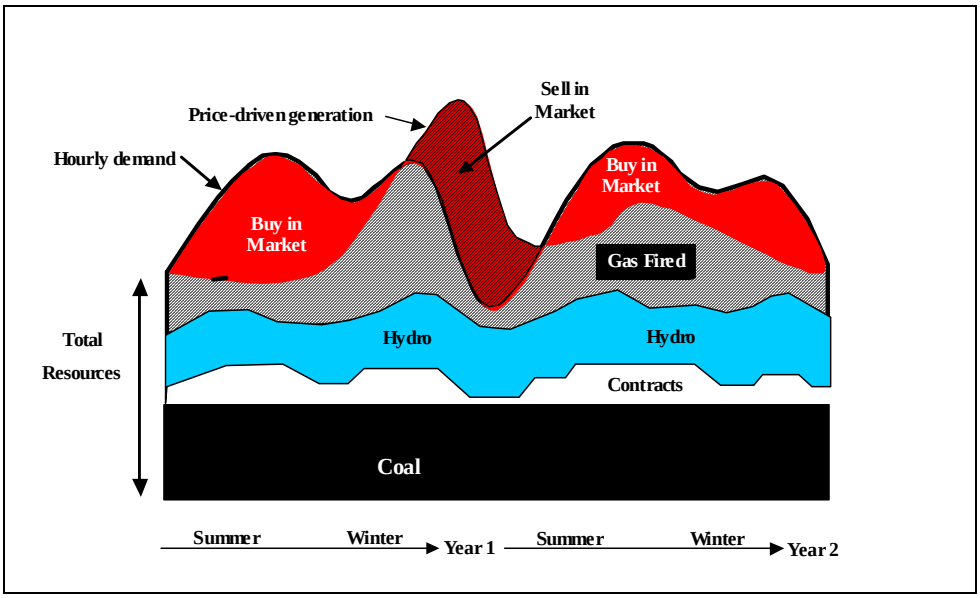


Figure 6-6: Portfolio Model Calculation

Typically, simulating 750 futures for each of 1400 plans would require that around a million scenarios be examined. If hourly calculations were performed for each of these 20-year scenarios, computation time would be prohibitive.[4] For this reason, algorithms were developed to estimate plant capacity factors, generation, and costs for periods of one to several months. Using these techniques, the 20-year study period is represented by 80 hydro-year quarters on peak and another 80 off peak. Since the model does not break the Northwest into sub-regions, cross-Cascade and other intra-regional transmission constraints are not modeled, but imports and exports are constrained to 6,000 megawatt-quarters, before any contracts.[5] Transmission constraints within the region are considered outside the model. Existing regional thermal resources are aggregated 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 component of the analytical system helped find the least-cost plan for a given level of risk. This component is actually another Excel add-in.[6] 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:

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

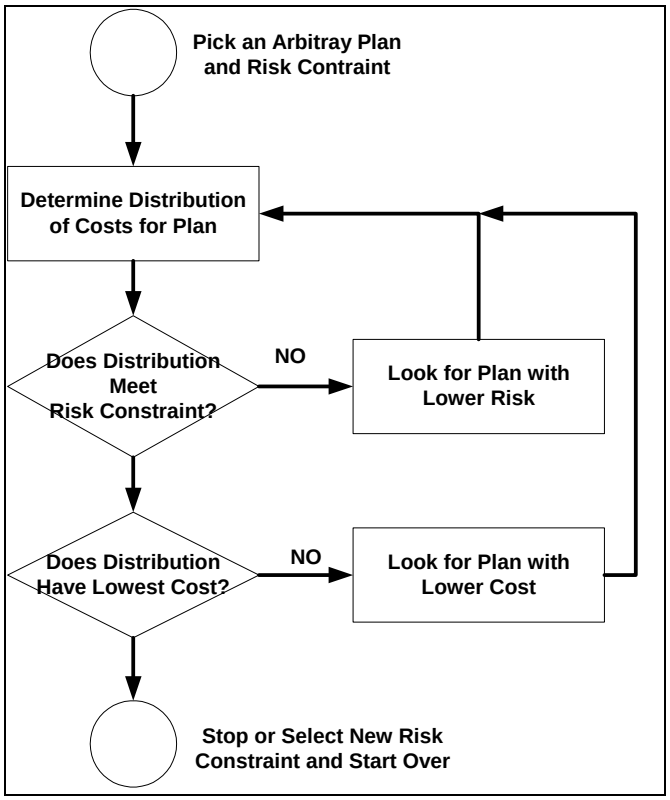


Figure 6-7: Finding the Risk-Constrained Least-Cost Plan

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

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. Assume that cumulative capacity expansion for four or five resource candidates were constrained to half a dozen levels at each of eight points in time.[7] Even with this modest choice, the number of potential plans is billions of billions.

If the outcome for each plan is plotted as a point with coordinates corresponding to the expected cost and risk of the plan, one obtains the new distribution illustrated in Figure 6-8. Each point on the figure represents the average cost and $TailVar_{90}$ value for a particular plan over all 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 lowest cost. Choosing from among the outcomes on the efficient frontier, however, requires accepting more risk in exchange for lower cost, or vice

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

versa. The "best" outcome on the efficient frontier depends on the risk that can be accepted. This topic is described in greater detail in Appendix P.

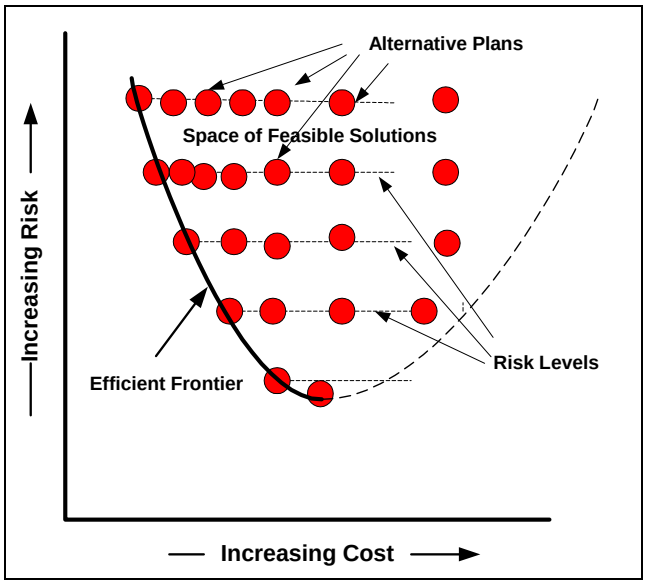


Figure 6-8: Feasibility Space

Application of the Efficient Frontier

One of the difficulties that surfaces when valuing resources is how to normalize the value for differences in risk mitigation. For example, one decision maker may adopt a least-cost plan that provides no protection from fuel price risk because he or his constituents have a high tolerance for risk. He may not be willing to pay a premium for a resource like wind generation that protects his constituents from excursions in rates due to fuel price volatility. Another decision maker may prefer a low-risk plan, which requires paying some premium -- relative to today's view of cost effectiveness -- to acquire those resources that provide this protection. Consequently, value typically follows risk aversion.

The efficient frontier provides a means to quantify the value of resources that provide some kind of risk mitigation and to explicitly describe that value as a function of risk aversion. Removing the resource as an option for capacity expansion leads to one of two outcomes: either the efficient frontier shifts to the right[8] along part of its extent, indicating costs have increased, or it does not. If the efficient frontier does not shift, it means other resources are capable of substituting for the resource in question. The resource therefore has no value at that level of risk. If the frontier shifts, the difference in cost at each risk level is the risk value of the resource. Figure 6-9 illustrates this effect for a typical resource.

[8] Removing the resource creates a set of resource options for the cost-minimizing logic that is strictly smaller than the original set. This implies that costs may not decrease.

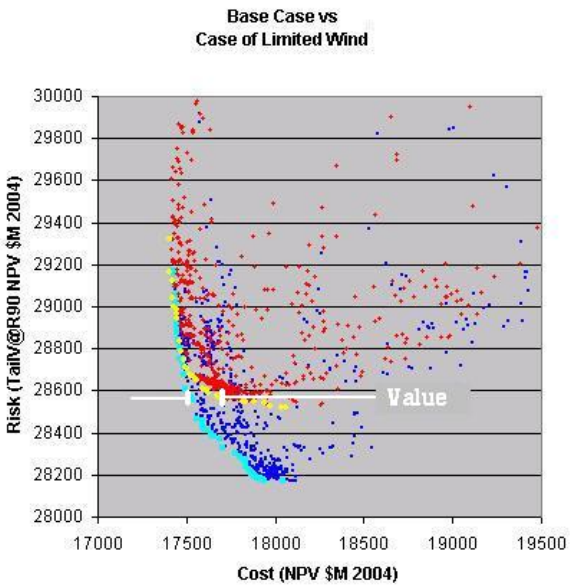


Figure 6-9: Value of Risk Mitigation Resource

What does this value represent? The efficient frontier using the candidate resource already captures the costs for planning and construction of the resource. The difference represents the value associated with assuring the resource is available at the cost and terms the model assumes.

The Risk/Cost Trade-off

The Council and the System Analysis Advisory Committee have extensively discussed the issue of risk/cost trade-off. 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 region, consideration of risk issues and the efficient frontier can provide insights for the Council and others in the region.

First, it may not be necessary to pick a risk/cost trade-off. The efficient frontier alone can yield significant insights. Attributes that are common or absent from among all the plans on the efficient frontier can help a decision maker to identify robust resource strategies and flag potential strategic blunders. As the next chapter explains, the common attributes turned out to be key to elements of the Council's Action Plan.

Second, many plans along the efficient frontier may differ only by commitments that do not need to be made today. If the earliest resource commitments from among all the plans occur at some point in the future, decision makers can and should wait until to make them. At that future time, the decision makers will have more information and a better choice may be more apparent. A useful product of the exercise, nevertheless, is observing the earliest that any commitment would be necessary. This observation can inform the timing of future planning efforts.

Third, partitioning plans along the frontier into classes of strategy can make planning more manageable. Typically, plans along the efficient frontier do not follow a simple, "more resources mean less risk" pattern. The analyst will observe regimes where different technologies

and strategies prevail, or different kinds of risk dominate. Using representative plans from each regime can help simplify subsequent analysis.

Fourth, the region's risk situation is likely to be representative of that which some parties in the Pacific Northwest power industry face. The conclusions and methods presented here may help others with assessing and communicating their risks and risk mitigation activities. Several general principles, described in the next chapter, may have value to individual industry participants.

Moreover, the analysis presented in the power 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. As described in the previous section, this analysis estimates the value of various resources and actions, including risk mitigation value.

At the beginning of this chapter, the question was raised, "How much generation is enough, and are there ways to assure its development?" Regulatory and legislative policies may be necessary. However, power systems and financial systems are complex, and regulatory policies can create ill-fitting, inequitable, and inefficient solutions in any particular situation. Individual participants, by insuring themselves against the risks that they face can help to secure a more reliable system for the region. The tools and methods developed for this analysis are available to decision makers in the region. Standard reports of risk analysis results may help regulators, load-serving entities, and their constituents communicate better.

The next chapter will take a more in-depth look at the issue of risk/cost trade-off for the specific efficient frontier the planning process delivered and plans along that frontier. $TailVaR_{90}$ has served well as a means of screening plans for risk, but that chapter presents values for other kinds of risk. This issue of alternative measures for risk raises the question of how $TailVaR_{90}$ compares to alternative risk measures.

ALTERNATIVE MEASURES OF COST AND RISK

Many alternatives exist for measuring the central tendency and the risks associated with a distribution of costs. Would the efficient frontier look different using alternative measures of risk or cost?

The results of portfolio model studies include a host of alternative measures. For each feasibility space study, data for each plan include both the median and the mean cost of the distribution. The model also tracks a host of risk measures. Risk data include:

1. $TailVaR_{90}$
2. Standard deviation
3. VaR_{90}
4. $CVaR_{20000}$
5. 90^{th} Decile
6. Mean (over futures) of maximum (over 20 years) of annual cost increases
7. Mean (over futures) of standard deviation (over 20 years) of annual costs

Subsequent studies examined alternative sources of risk, such as relative exposure to bad market conditions and variation in average power cost, including embedded costs.

Mean costs and TailVaR$_{90}$ do a reasonable job of screening plans. For modeling the regional portfolio, there is a strong consistency between the chosen measures and the alternatives in most cases. This correspondence is neither accidental nor universal among load-serving entities in the region. This section describes the relationship for a couple of alternative measures and provides a reason for the correspondence. A complete treatment of the alternative measures appears in Appendix P.

An Alternative to the Mean

Some would argue that the median is a better measure of central tendency than the mean for risk analysis. The median future is a future above and below which lie an equal number of better and worse futures. In contrast, a weighing scheme defines the mean: the mean is the average of outcomes, weighed by their probabilities. What future will the region face? For that matter, what determines the outcome of rolling dice? It is a matter of the likelihood of landing on each face, not the value of the faces. The mean cost, in fact, may not correspond to any particular future, just as there is no face on a die with the value 3.5, the average outcome. For an odd number of futures, however, there is always a median value future[9].

On the other hand, the mean is a statistic with which most decision makers seem to have greater comfort. Some decision makers may feel that they want extreme outcomes to influence their measure of the central tendency.

Fortunately, it does not seem to make much difference to an analysis of regional risk. Distributions for outcomes of plans exhibit a strong relationship between the two measures. Figure 6-10 shows that the mean and median values track very closely.

The mean value is consistently above the median, suggesting that distributions of cost are skewed. The distributions have long tails extending in the high-cost direction, pulling up the mean. As costs go down, the skewing becomes more pronounced. This has implications to the discussion of risk measures.

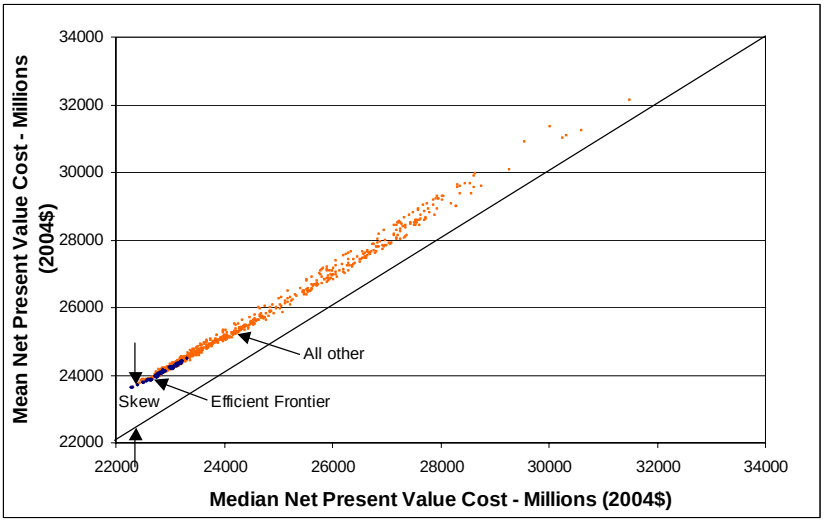


Figure 6-10: Mean vs Median

[9] The median of an even number of observations is the arithmetic average of the two middle observations.

Distributions of Cost for Regional Risk Study

Distributions of cost for typical load-serving entities or generators in the region differ significantly from that of the region as a whole, because individual participants are usually price takers. That is, their individual loads and the operation of their resources typically will not move prices in the region. If they have surplus resources, in particular, their potential for making money is large. It depends only on how the market price for electricity goes.

One potential cost distribution situation for price takers with surplus resources appears in Figure 6-11. Market prices for electricity may go down significantly, but prices are ultimately limited in how far down they can go. Costs are therefore limited to the fixed costs of resources surplus to requirements. The costs have a tail extending to the left in Figure 6-11 because high prices produce revenues that offset these fixed costs. Net costs can even become negative if prices, which are unbounded above, are high enough.

This situation does not arise for the region. This is because the aggregate regional resource situation affects market prices. Surplus resources for the region depress price. To see this, start with a resource-deficit situation. The cost distribution is skewed in the opposite direction (Figure 6-12), with a tail to the right. The reason for this shape is similar to that for the resource-surplus price taker, except that now there is a floor on fixed cost and more exposure to high prices of market energy to make up meet requirements. (Price takers who are *deficit* resources will potentially have this distribution of costs, as well.) The more resources added, the shorter the tail to the right becomes because the net requirement met by the market diminishes. When the resources are roughly in balance with the loads, the distribution becomes nearly symmetric. However, surplus regional resources depress price, so the distribution does not "flip around." Export constraints limit the sales from any surplus resources. Once the export constraints become binding, prices fall and so do profits from sales.

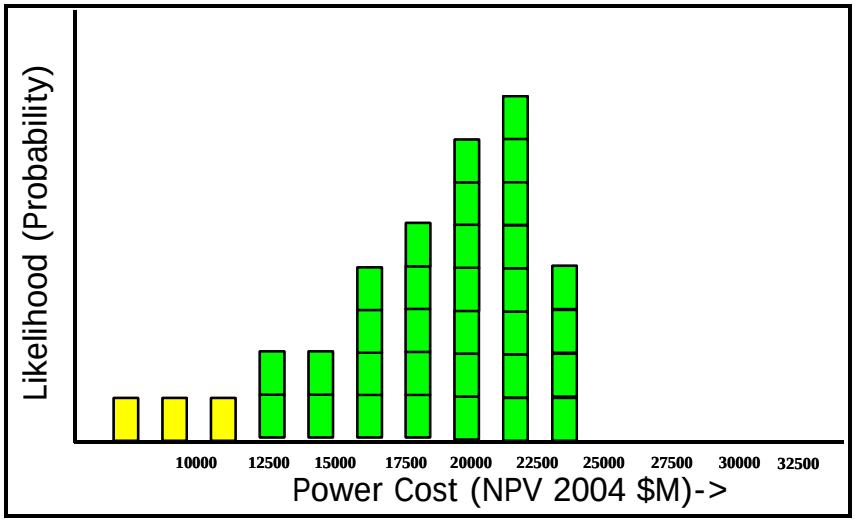


Figure 6-11: Cost Distribution for Resource-Surplus Price Taker

Because distributions like that in Figure 6-11 never arise in the regional study, the median cost is always lower than the mean cost. Moreover, what typically occurs is that the least-cost, highest-risk plan consists of relying on the market to meet requirements. In this case, of course, the

distribution for regional costs becomes highly skewed. This explains why skewing becomes more pronounced in Figure 6-10 at the lowest average cost.

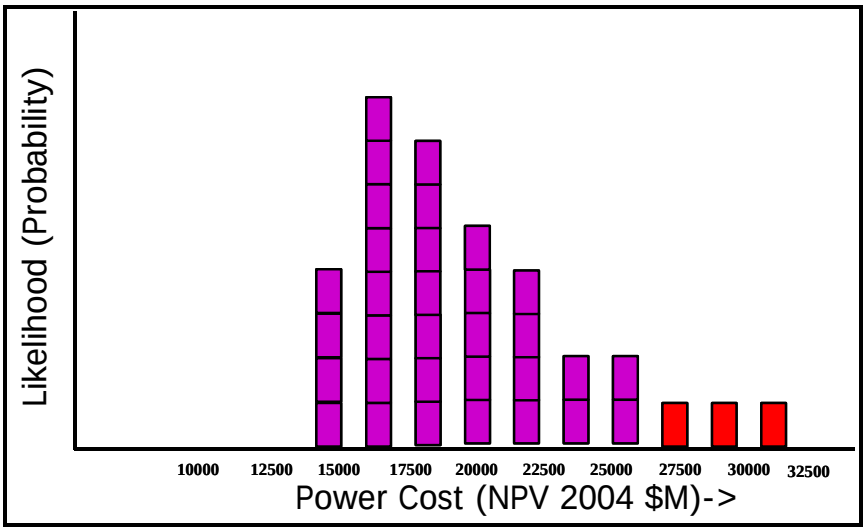


Figure 6-12: Cost Distribution for Region

Alternatives to TailVaR$_{90}$

The Council's portfolio analysis suggests that TailVaR$_{90}$ is a reasonable risk measure for the region. This section will explore alternative risk measures and explain why TailVaR$_{90}$ provides good guidance in evaluating regional plan risk.

To understand why TailVaR$_{90}$ is robust, consider the example of standard deviation. Figure 6-13 restates the feasibility space associated with the base case,[10] using standard deviation as the risk measure. In Figure 6-13, the white points are the plans in the efficient frontier or near-efficient frontier using TailVaR$_{90}$. Clearly, these are also efficient using standard deviation. The black diamonds are the plans that are efficient using standard deviation, but not efficient using TailVaR$_{90}$. These require explanation. The smaller, interior points correspond to plans that are not efficient using either risk measure.

To understand what is taking place here, recall the description of the distribution of costs for the region in the previous section. Cost distributions for the region are skewed in only one direction. If a plan is on the efficient frontier using TailVaR$_{90}$, the cost is minimal so the distribution is typically as narrow as possible given the level of risk. That is, a plan with a narrower distribution would have higher cost and would not be least cost. Standard deviation is therefore as small as possible. The converse is not true, in general. A plan could represent a lot of resource addition, which would suppress prices and create a very predictable, but expensive outcome, that is, a narrow distribution of costs. This is evident in the plans represented by the black diamonds. It is unlikely that a decision maker using standard deviation would choose these plans, however. In these plans, the cost for *each future* is higher than the cost any of the plans represented by the white points *under the same future*. This is not evident from the graph, but it is one of the important properties of coherent measures of risk, like TailVaR$_{90}$. Supposedly, a

[10] See description and discussion in the next chapter.

rational decision maker using standard deviation could identify these plans by their high cost and would exclude them from consideration.

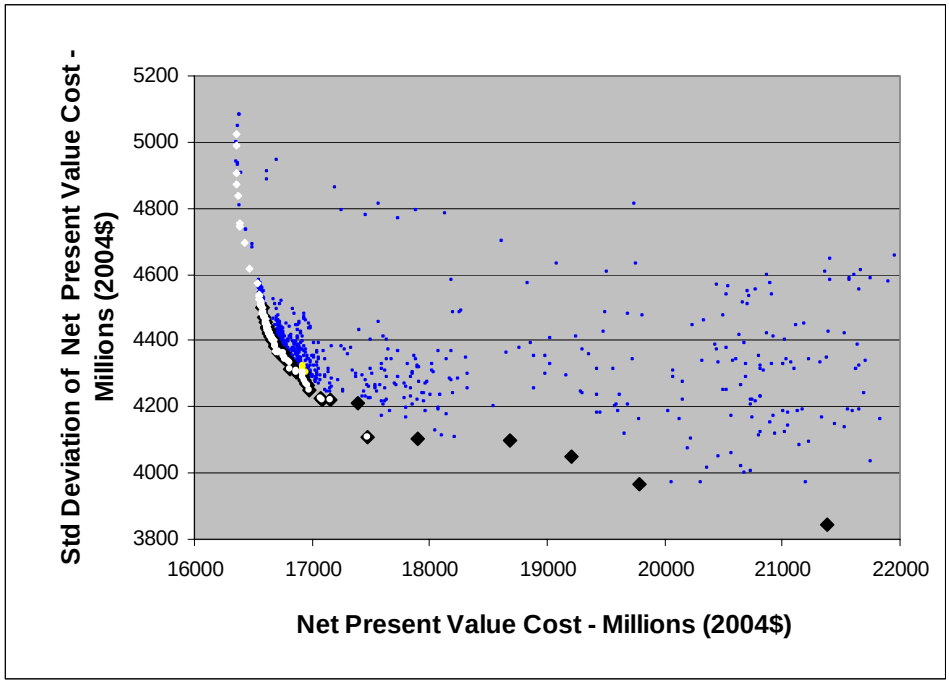


Figure 6-13: Using Standard Deviation to Create the Feasibility Space and Efficient Frontier

The analysis of correspondence of $TailVaR_{90}$ to other risk measures appears in Appendix P. Other coherent measures, like $CVaR_{20000}$, generally show a direct correspondence to $TailVaR_{90}$, whereas non-coherent measures, like Value at Risk (VaR), have a relationship to $TailVaR_{90}$ that resembles that of standard deviation. Along the efficient frontier, non-coherent measures will agree with $TailVaR_{90}$; away from the frontier, the agreement will be weak, but higher average cost would tend to remove the plans from consideration. The Council concluded that $TailVaR_{90}$ provides a robust measure of risk for screening regional plans.

Although cost distributions for the region skew in one direction, this is not true of load-serving entities that are price takers in the region. For these entities, coherent measures of risk are a better choice than non-coherent measures. The fortunate correspondence that exists between coherent and non-coherent measures of the regional cost distribution does not exist in their situation. For example, given a choice between a plan that produces a surplus and a plan that produces a deficit, the situation may arise where average cost and standard deviation are identical, as illustrated in Figure 6-14. The risk situation, however, is quite different. The deficit plan has a tail that extends in the high-cost direction, a riskier situation.

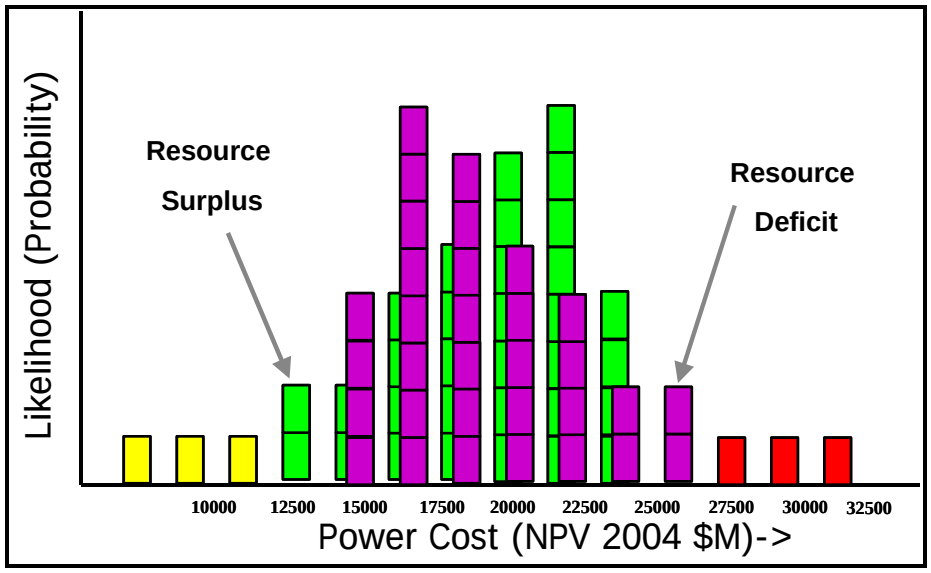


Figure 6-14: Price Taker's Cost Distributions for a Resource-Surplus Plan and a Resource-Deficit Plan

This concludes the discussion of uncertainties and sources of risk. This chapter now turns to the topic of risk management and mitigation.

RISK MITIGATION ACTIONS

How risk reduced, 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 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

"Hedging your bets" is a common phrase. It means an action that will offset the effects of another action. 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 of 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. However, hedges are not free. If natural gas prices decrease, 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 to hedging, there are risk measures that provide "optionality" or "flexibility" and are asymmetrical in their effect. One of the most familiar examples is insurance. Home and car insurance protects the owner from futures or situations that diminish or wipe out the value of the investment. The insurance premium offsets a part of the value of the investment in all futures, but the insurance shields 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 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 short-term 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 sell the electricity generated from the gas. 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 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, and other demand response programs where consumers reduced demand in response to financial inducements. Other examples of the value of planning flexibility included reductions in spill that made additional hydro generation available and diesel generators that came on-line very quickly.

The treatment of flexibility, and in particular long-term planning flexibility, distinguishes the Council's study and analytical technique from many of the techniques currently used to evaluate resource plans. This distinguishing feature is critical to the Council's evaluation of risk. The following section describes how the portfolio model captures the value of modularity, short-lead time, and cost-effective deferral of construction.

Resource Additions and Decision Criteria

Planning flexibility allows a plan to accommodate changes from one future to another. By automating this process and applying probabilities to the various futures, the portfolio model can

estimate the expected cost of accommodating the full range of futures. Plans containing resources that have more planning flexibility can manage this accommodation at a lower expected cost, other things being equal.

The value of flexibility stems from the ability to change plans when unforeseen events occur. This implies that a risk model must incorporate at least two special features.

First, a risk model must have the ability to add resource capacity without the benefit of perfect foresight. Most production cost or system simulation models capable of capacity expansion use techniques that assume perfect foresight. For example, these models may remove resources that do have sufficient value in the market to cover forward going fixed costs or add resources that would make a risk-adjusted profit in the market. An iterative process removes or adds resources until all new resources would just cover their risk-adjusted costs. Alternatively, a capacity expansion model may choose a capacity expansion schedule that minimizes cost. Both of these approaches must determine future hourly costs and prices to feed back to the capacity expansion algorithm. This feedback determines whether some adjustment to the construction schedule is necessary. If the model modifies the schedule, of course, the model must re-estimate future costs and prices change. The process repeats until the model finds a solution. These estimates of future costs and prices represent perfect foresight regarding how resources, costs, and prices affect one another. Perfect foresight, however, is contrary to the principles of risk analysis.[11]

Second, a risk model that incorporates capacity expansion must have a decision rule that determines whether to build or continue building. Because a risk model cannot use perfect foresight, the value of this criterion must use information about the current situation or about the past. Of course, different resources may use different criteria. A good test of a decision criterion, as it turns out, is whether it reduces cost and risk.

A decision criterion need not be perfect. The assessment of the value of planning flexibility relies on how well a resource plan performs when circumstances *do not* materialize as planned. As long as the decision criterion add resources and makes wrong forecasts (from the standpoint of perfect foresight) in a realistic manner, it could be deemed adequate.

The Council evaluated several approaches to decision criteria. For conventional thermal resources and wind generation, the approach that performed best incorporates information about resource-load balance and forward prices for fuel and electricity prices. Specifically, the model uses a three-year average of load growth and any change in resource capability to determine when in the future resource-load balance would cross below a given threshold. The selection of the threshold is itself part of the choice the model makes to minimize cost or risk. In each simulation period and for each resource candidate, the model determines whether the crossover point is less than the construction time required for that resource.

If the model needs a resource to meet anticipated future load, the criterion consults pertinent forward prices for each resource. For example, for a gas-fired power plant, the model would estimate the plant's value from forward prices for electricity and natural gas and compare those

[11] A peculiar side effect of perfect foresight models is they often lead decision makers to rely on the market. Capacity expansion models with perfect foresight add power plants precisely when they have greatest value. Following this approach, however, leads to market prices that match the fully allocated cost of the capacity expansion alternative or to long-term marginal expansion costs that match market prices. Given that the decision maker is no better building a plant than she would be if she purchased firm power in the market, there is little incentive to incur the considerable risks and challenges of building.

to capital and other fixed costs to determine whether the plant would pay for itself. If the plant would pay for itself, construction proceeds; if not, the model compares the value of the plant to that of alternatives. If the plant cannot pay for itself but is still the least expensive alternative, construction continues.

The model uses forward prices for electricity, natural gas, and other commodities, but it cannot use perfect foresight. Consequently, the model estimates forward prices using the assumption that futures and forward prices closely track current prices. This relationship is apparent in data for many commodities, including natural gas and electricity, where storage of the commodity is limited. The average commodity price over the last 18 months is the forecast of forward prices, reflecting the fact that it often takes a while for perceptions about long-term price to change.

Each resource that is a candidate for capacity expansion uses its decision criterion to control progress on construction, depending on where the resource is in its construction cycle. The decision criterion typically assumes one of two values, corresponding to either "Go" or "No Go" instruction, as illustrated in Figure 6-15.

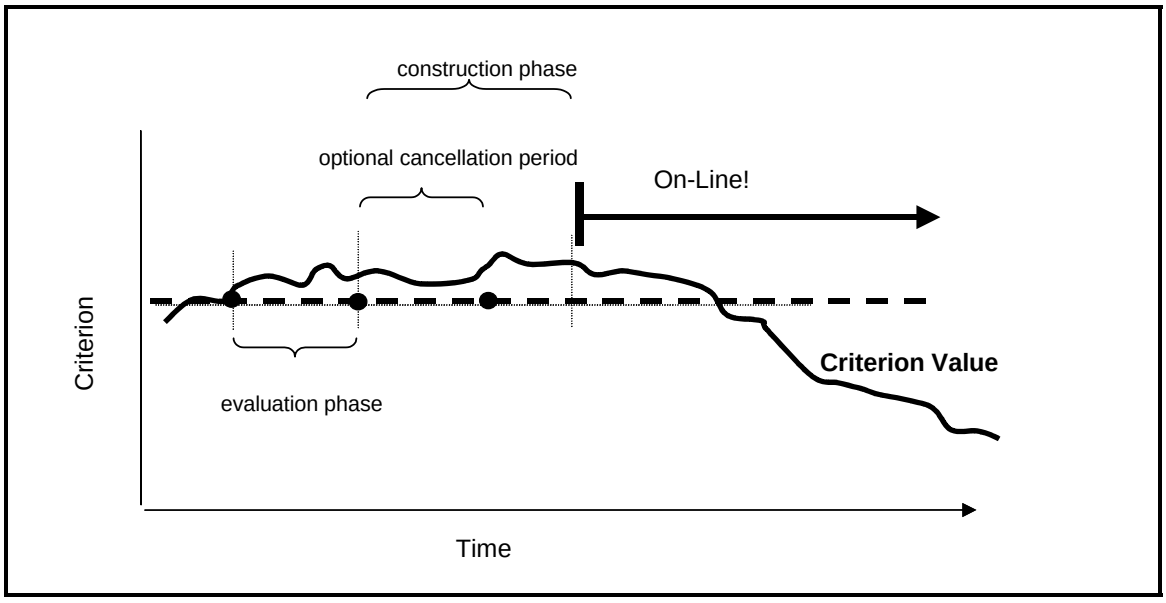


Figure 6-15: The Decision Criterion Value Over Time

The construction cycle for power plants typically consists of three distinct periods. (See Figure 6-16). During the first period, planning, siting, and permitting takes place. The regional portfolio model assumes planning costs are sunk. The purpose of the plan, in fact, is to determine for which, and for how much of each resources the region should complete such preliminaries. The second period commences with the first substantial, financial commitment. This might include activity such as substation and building construction, or an initial order for boilers or turbines. During this critical second period, the plant owner may delay or cancel construction if circumstances dictate. This period may last from several months to several years, depending on the resource, or it may not exist at all. The regional model captures this flexibility by delaying or canceling construction when the decision criterion indicates progress would not be advantageous. The model then incurs mothballing and cancellation costs for the plant. After

this second period, however, a final commitment typically is required which compels the plant owner to finish construction. An example of an event that would trigger the third and final period is the receipt of and final payment for the turbine or boiler. These items are often the largest, single expense during construction. During this third period, construction activity in the model ignores the decision criterion.

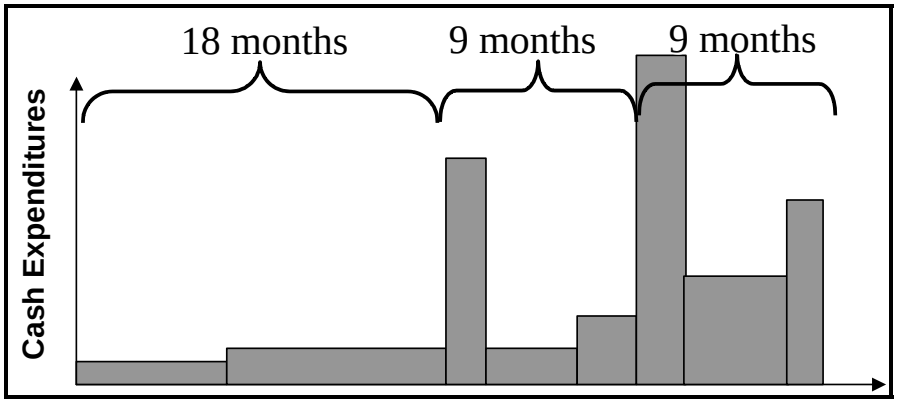


Figure 6-16: Stages of Cash Flow

Given how important the decision criterion is to assessing planning flexibility, it is natural to ask what alternatives exist and why the Council chose this particular decision rule. The first rule implemented in early versions of the portfolio model was valuation using forward prices, much as described above. One concern that arose when consideration turned to valuing conservation is that conservation often received value by virtue of "being there" when high market price excursions occurred. Resources that used only valuation in the market could only react to these excursions; often completing construction after the excursion subsided. Although this may help describe behavior during the 2000-2001 energy crisis, a more experienced market will probably pay careful attention to physical resource requirements in the future. Moreover, when a resource-load balance criterion replaced the market valuation criterion in the portfolio model, the feasibility space and its efficient frontier displayed reduced risk at no increase in cost. Resource-load balance does a better job of predicting the need for resources.

Resource-load balance alone, however, presents some problems as a decision criterion. An examination of particular futures revealed unrealistic behavior. Resource-load balance ignores economics completely. Given a future with high gas prices, for example, the portfolio model would be as likely to develop a gas-fired turbine as a coal plant if it has a choice between the two. Consequently, the criterion in the final version of the portfolio model gives consideration first to resource-load balance and then uses plant valuation to make the resource choice.

Conservation uses a slightly different decision criterion. Conservation can introduce thorny problems, like cost shifting for ratepayers and revenue recovery for load-serving entities. Consequently, special regulatory or administrative intervention is typically necessary. Cost effectiveness has been the standard that administrators use to deem the type and amount of conservation to pursue.

Because conservation uses a cost effectiveness standard, a criterion that resembles such a standard seems appropriate. However, the challenges in constructing a cost effectiveness criterion are several.

- Cost effectiveness levels change over time as market prices for electricity change, although administrators tend to base them on long-term equilibrium prices for electricity. Models that estimate equilibrium prices for electricity are sensitive to commodities that have been less volatile than electricity prices, such as natural gas price. Regardless, cost effectiveness standards are subject to uncertainty and change depending on the particular future.

- Because they are often determined administratively, they change more slowly than commodity prices. Moreover, the time between changes in efficiency standards and when the conservation measure starts to contribute can be a year or more, while load-serving entities develop their budgets and ramp up programs. Thus, there is considerable lag time between changes in commodity prices and changes in conservation energy rate of addition.

- Some types of conservation become institutionalized, such as that associated with new codes and standards for building construction. Once the codes pass into law, the corresponding measures are no longer directly subject to the cost effectiveness standard. Thus, the decision criterion for this kind of conservation is "sticky downward." It does not decrease, and it increases only when the cost effectiveness standard passes the previous "high-water mark."

- The NW Power Act requires that the power plan assign a ten percent cost advantage to the acquisition of conservation. By using a criterion that accessed the supply curve as a level at least 10 percent higher than a market-based cost effectiveness standard, the portfolio would accommodate this requirement.

- A long-standing Council objective has been to understand what value there may be in sustained, orderly development of conservation. Is there any advantage to this policy over the sustained, orderly development of any other resource? Is there any cost or risk advantage to developing more conservation than a conventional cost effectiveness standard would suggest?

These considerations drove the design of the decision criteria for conservation. In the case of conservation, the decision criterion takes the form of a price. This price and a supply curve determine how much conservation to develop in a given period. Both lost-opportunity and discretionary conservation[12] criteria are the sum of two terms. The first term approximates the cost-effectiveness standard. This is a "myopic" estimate of cost effectiveness, which depends on the specific future and changes over time in that future. The second term determines how much additional conservation to deploy compared to the cost effectiveness level. This second term, a price adjustment, is under the control of the logic that helps the portfolio model find the least-cost plan, given a fixed level of risk. (See Figure 6-7.)

The specific rules for estimating the going-forward cost effectiveness standards appear in Appendix L. The discussion of conservation in Chapter 3 shows the effect of alternative rules on

[12] The description of these classes of conservation appears in Chapter 3

cost, risk, and acquisition levels. The reader will also find in Appendix L a discussion of the effect that the shape of the supply curve has on the value of conservation under uncertainty. This discussion explains the relation between the price adder and the reduction of cost.

Finally, this section has emphasized the role of planning flexibility and the decision criteria, but the reader should remember there is another important element that determines construction. The logic that helps the portfolio model find the least-cost plan plays an equal, if not larger role in which resources can show up in a given future. This logic determines which resources have completed the pre-construction stage and, therefore, which resources are *available* for construction.

This is the purpose of the resource plan produced by the portfolio model: to determine which resources to prepare and when to commit to their deployment. The next chapter describes the resource plan that the Council selected and provides additional interpretation of the plan's schedule for construction and action.

Portfolio Analysis & Recommended Plan

Chapter 6 described how the Plan addresses cost and risk, and introduces the ideas of a feasibility space and its efficient frontier. This chapter describes the plans that appear on the efficient frontier and outlines how the Council selected a single plan from among them.

BACKGROUND AND OVERVIEW

The notions of a feasibility space and its efficient frontier are powerful tools for thinking about risk management. For a simple financial instrument, such as an insurance policy, they might tell enough about the situation to suggest a plan. It would come down to the payout and probability of the payout. Unfortunately, the task of selecting a resource plan for the region is not so simple.

Systems as complex as the Northwest power system require close examination from many perspectives. Other issues not fully represented by the feasibility space include predictability of cost to ratepayers, environmental impacts, and risks associated with the feasibility of developing the technologies in sufficient quantity to meet uncertain schedules of requirement. The risks associated with some of these are monetized, but additional study reveals issues that merit consideration. It becomes clear that the feasibility space and efficient frontier are really a means to filter down the number of plans to a handful for more careful study.

This chapter lays out the analysis of the most promising plans and describes the process the Council followed to arrive at a long-term resource strategy and Action Plan. First, the chapter explores in some detail the plans that fall along the efficient frontier. Given the complex nature of the Northwest power system, how are the other issues like cost predictability changing along and near the efficient frontier? Second, the discussion turns to similarities and differences among the plans on the frontier. Several sensitivity analyses provide addition insight into how plans differ. Consideration must be given not only to technology selection, timing, and sizing but also to when the region must commit to these decisions. Observations about the similarities among plans along the efficient frontier provide guidance in choosing "a" resource plan for the next 20 years and measures for the Action Plan.

Third, the chapter explores specific elements of the Action Plan, such as demand response, conservation, and preparations for future resources. Fourth, a section entitled "Scenarios" uses selected futures to illustrate how the plan adapts to changing circumstances. Finally, the chapter concludes on a philosophical note. A 20-year schedule of resources that stems from notions like risk-constrained least-cost planning is easily misinterpreted. The chapter attempts to describe not only the insights this approach provides but limitations of its application, as well. The Plan is not a static blueprint. It is a vision that informs a continuous planning process. Properly interpreted, this Plan can help the region identify milestones and warning flags that may arise during this process.

Each of the steps just described requires considerable discussion. To keep the reader oriented, the next section starts with a brief overview of the process that led to the recommended plan. With this as a map, the section then revisits each topic in turn.

DEVELOPING THE PLAN

Developing the plan required several years of work and but it can be described in relatively few steps. The following steps led the Council to select the plan.

1. Developing a base case -- Characterizing the power system, uncertainties, and resource behavior demanded time and thought. The product is the key assumptions. With key assumptions fixed, the portfolio model created the feasibility space that was a benchmark for exploring certain issues, such as the value demand response.
2. Examining the efficient frontier and near-frontier -- The relevant plans are the least-cost plans for each level of risk. The choice of a plan involves many more considerations than cost and $TailVaR_{90}$ risk. Similarities and differences among the plans provide important insights.
3. Considering alternative perspectives on cost and risk -- The measures of cost and risk chosen for creation of the feasibility space are robust, as discussed in the preceding chapter. Nevertheless, in deciding from among the selected plans on the frontier, alternative measures such as power cost volatility, power system reliability (e.g., loss of load probability), and exposure to market price excursions can provide additional sources of discrimination. In some cases, they also provide a more intuitive indication of risk than $TailVaR_{90}$ or its alternatives.
4. Identification of the Action Plan -- Several decisions appear to have clear choices, because actions are called for in all the plans along the efficient frontier and they require commitment within the next five years. These actions comprise the Action Plan. Other actions may not require immediate commitment, but their timing provides the region with an idea of how soon re-evaluation is necessary.
5. Creating implementation milestones for the Action Plan -- Given the importance of the commitments in the Action Plan, it must assure the region that its elements are feasible and cost-effective.

With this overview in hand, the remaining portions of this section deal with these steps in detail.

Developing a Base Case

As described in chapter 6, the portfolio model is used to develop a number of alternative power plans, all of which lie along the efficient frontier. Each represents the least cost plan for a given level of risk. A “plan” consists of amounts and schedule for the development of lost opportunity and non-lost opportunity conservation; demand response; and the amounts and schedules for the “be prepared to begin construction” or “option” dates for generating resources.

Assumptions that pertain to candidate resources for future growth in requirements, merit their own description. Conservation resource potential is described in Chapter 3. Fixed

assumptions regarding the availability and cost of demand response are described in Chapter 4. Generating resource characteristics are described in Chapter 5.

A thorough discussion of those pertaining to uncertainties, such as gas price uncertainty, appears in the previous chapter. The following is a brief description of other key assumptions that do not fall into either of those categories:

- Electricity price cap of $250 per megawatt hour -- Prices for wholesale electricity price are capped at $250 per megawatt hour on average for a quarter. This value corresponds to that of price caps imposed in the Western power system. Electricity prices rarely hit this level in the portfolio model, but removing the caps would result in greater value for resources that reduce risk, such as demand response.

- IPP plants not currently under contract provide energy for the regional market, but the IPP owners -- not the region -- receive the benefits of this generation. There are about 3000 MW currently not under contract to regional utilities. This generation does not have firm transmission access to markets outside the region. The amount that is under contract declines over the next few years. The IPP resources could have as much as $4 billion in value to the region over the planning period. Much of the value would come from reduced exposure to market prices and from deferring or displacing the resources identified in this plan. However, it would cost the region some significant fraction of that value to acquire those resources. Without knowing the contract or purchase terms that utilities might enter into, it would be imprudent to assume these resources are available to reduce regional cost or risk.

- Declining resources -- The portfolio model currently does not retire resources based on economics. Study suggests that the portfolio model would tend, in low-risk plans, to retain resources despite there being futures with extended periods of low wholesale prices. For this analysis, the capability of the hydro system is reduced by approximately 300 average megawatts over the planning period. This is an estimate of the potential net reductions in capability as a result of relicensing and other developments and increases resulting from turbine improvements.

- Portions of east-of-region coal plants are available -- Jim Bridger, Colstrip, and several other power plants, although not physically located in the region, are traditionally considered regional resources. A significant portion of the operators load may be located in the region, for example.

- Resources that have very good chance of completion are included -- The modeling assumes over1100 megawatts of wind development by 2012 from Oregon and Montana system benefit charge programs and near-term utility wind acquisitions are in the resource base. It also assumes that certain other thermal resources having high probability of completion, will contribute. Most significantly, this includes the Port Westward combined cycle combustion turbine

(400 megawatts capacity including duct firing capability).

- One region for transmission purposes -- Significant and numerous transmission constraints exist in the region. These do not appear explicitly in the model, although the analysis and interpretation of any plan incorporates them. The portfolio model considers looking at loads and resources in aggregate. Actual siting of plants will require detailed consideration of transmission.

Early analysis with the model employed a cross-Cascades transmission constraint but the preceding observations led to abandoning the two-region approach. Where transmission is a sizeable consideration in the choice of a resource, such as new generation out of Montana or Wyoming, special studies and conversations with transmission experts provided understanding about the specific candidate. More details about these and other assumptions are available in Appendix L.

New generating resource options considered in the portfolio analysis are limited to those judged to have the potential to become significant players during the 20-year period of the plan. These include natural gas combined-cycle gas turbines, natural gas simple-cycle gas turbines, wind power plants, coal-fired steam-electric power plants and gasified coal combined-cycle combustion turbines. Though not currently considered "available", as required by the Regional Act, natural gas fired cogeneration plants sited in the Alberta oil sands region were tested in sensitivity studies. Generating resource options are described in Chapter 5.

The initial analysis assumes that non-lost opportunity or discretionary conservation could be developed at rates up to 30 average megawatts per quarter. This rate is thought to be aggressive but doable. Because many of the lost opportunity resources identified are relatively new, it was estimated that it would take 12 years before the lost-opportunity resources could be fully developed (85 percent of the potential). This means that would take 12 years before programs, codes and standards capable of securing 85 percent of the lost opportunity resources identified in Chapter 3 could be in place and functioning at that level.

The Efficient Frontier

The portfolio model, using the assumptions described in the preceding chapter, created the feasibility space illustrated in Figure 7-1. Each point represents the expected (average) cost and risk values for a single plan over 750 futures. The "efficient frontier" is made up of those plans that have the lowest expected cost for a given level of risk. The construction and interpretation of the feasibility space appear in the preceding chapter.

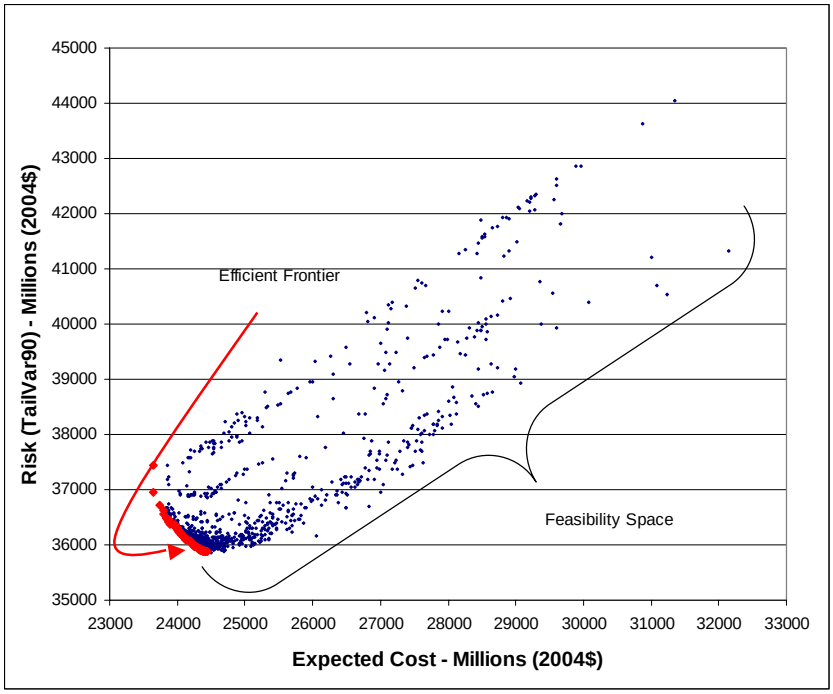


Figure 7-1: Feasibility Space and Efficient Frontier

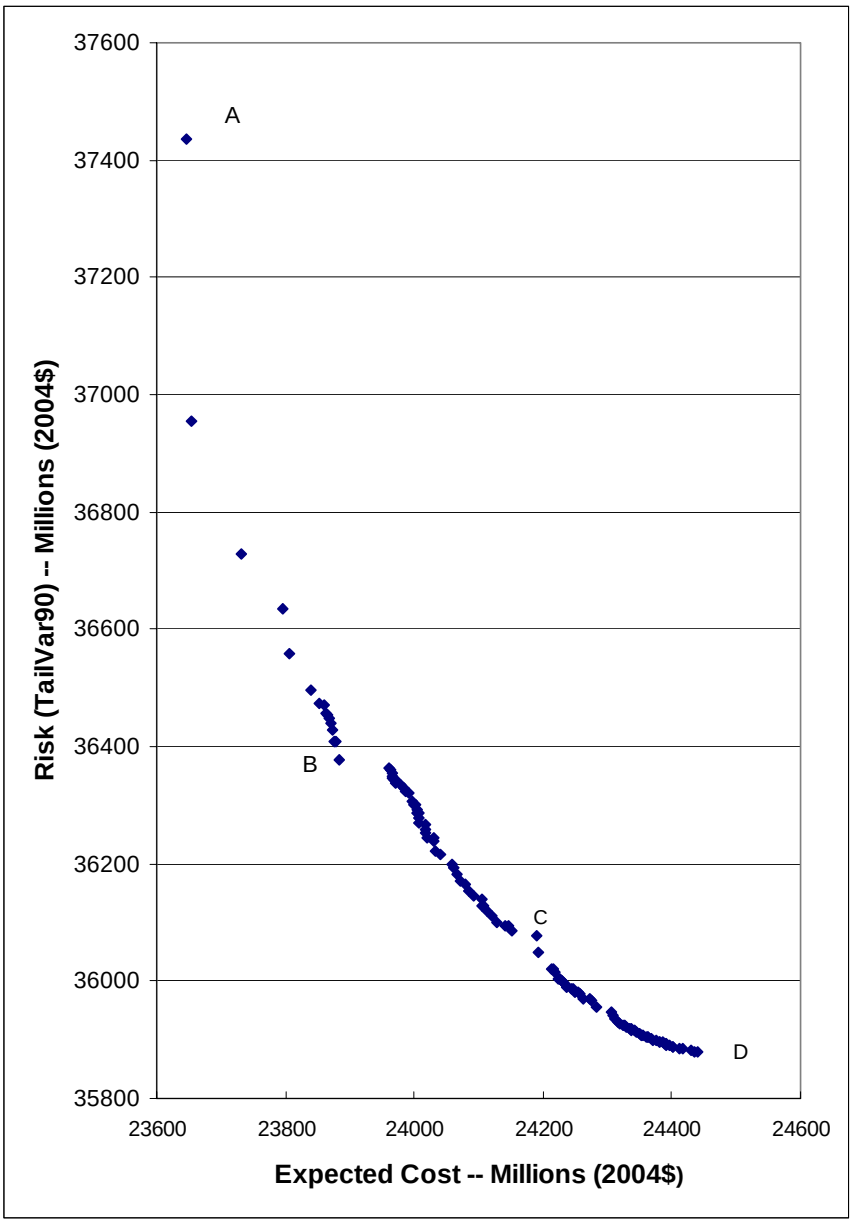


Figure 7-2: Plans Along the Efficient Frontier

The resulting efficient frontier is illustrated in Figure 7-2. Four specific plans are noted on Figure 7-3, including the absolute least-cost plan (A), the absolute least risk plan (D) and two intermediate plans (B and C). Each plan along the efficient frontier is the least cost plan for that level of risk.

If plans near the efficient frontier differed significantly from those along the frontier, it would certainly warrant additional exploration. Those plans within a quarter of a billion dollars cost and risk, however, resembled closely those on the efficient frontier. Only those plans well away from the frontier, where typically larger amounts of generation are added, had significantly different schedules.

Differences Among the Plans

Moving along the efficient frontier from the absolute least cost plan to the absolute least risk plan, expected cost increases while the risk decreases. Developing conservation and demand response and creating generation resource options provide risk reduction. This, of course, incurs additional cost, on average. The differences in the resource portfolios for these plans are illustrated in Figures 7-3A through 7-3D. These figures show representative "in-service" dates for the various resources as well as their energy capability. Actual in-service dates will vary depending on the characteristics of the particular future being evaluated. The date at which the region needs to be prepared to begin construction depends on the construction lead-time. For example, actual construction of conventional coal-fired generation must be started 42 months in advance of the in-service date. For wind, the lead-time is one year. The construction lead times and the associated costs are described in detail in Appendix I.

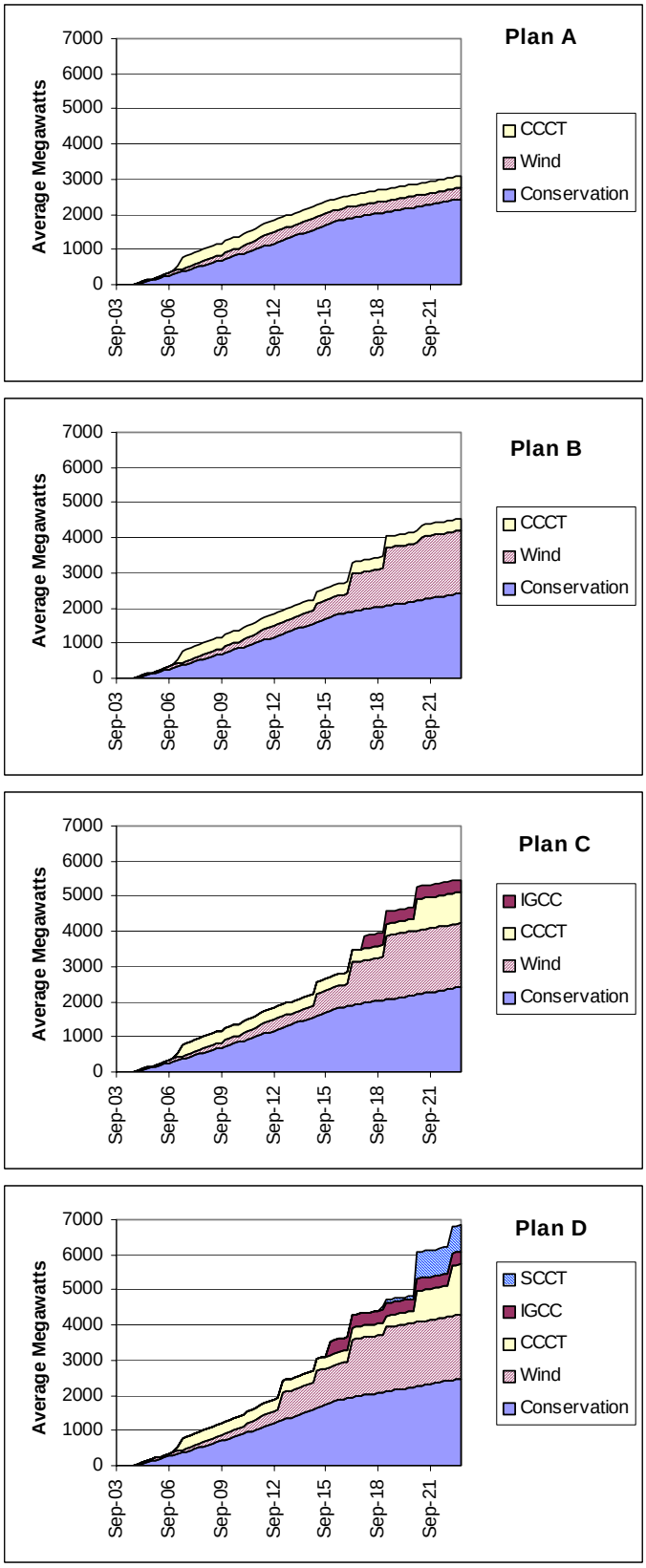


Figure 7-3: Representative Development Schedules for Altenative Plans along the Efficient Frontier

Plan A – In addition to the already committed combined cycle combustion turbine generation (CCCT) and wind, this plan relies on conservation, market purchases and demand response. Demand response is usually dispatched relatively infrequently and the associated energy is small and is not shown. This plan has the lowest expected cost but it is the plan most exposed to market risk, as is reflected in its higher risk value.

Plan B - This plan offsets some market risk by adding the ability to develop additional wind generation in the latter parts of the planning period. Demand response continues to be utilized, although less heavily than in the least cost case.

Plan C - This plan adds the ability to develop 425megawatts (capacity) of gasified coal generation (IGCC) as well as somewhat earlier construction of wind and 1200 megawatts of combined cycle combustion turbine capacity late in the planning period. Demand response, though not shown, continues to play a role, albeit at a reduced level.

Plan D – This plan adds greater diversity with the ability to develop additional combined cycle and single cycle gas-fired combustion turbines (SCCT) close to the end of the planning period. This plan has the highest expected cost among plans on the efficient frontier, but the lowest risk.

Similarities Among the Plans

There are at least two important points of commonality among the plans. First, conservation and demand response are present in all the plans in similar quantities. Demand response is dispatched less frequently in the lower risk plans. This is the effect of lower electricity market prices that result from more resources being available. Nonetheless, it plays a significant role in terms of reducing cost and risk in all the plans.

Second, there is no major plant construction during first few years beyond those resources assumed to be already committed. For those plans with new generation, earliest construction start date would be early 2010 for wind generation. The earliest construction start for gasified coal generation would be early 2012.[1] The implication is that relying on already committed resources, conservation and the market for the first few years is the lowest cost approach for any level risk. As has been discussed earlier, there are valid reasons why individual utilities that are resource short might choose to go forward with resource acquisition in the near term. However, from a regional standpoint, pursuing conservation and demand response for a few years until the regional surplus of generating capacity erodes appears to make sense.

Least Cost, Least Risk, or Plans In-Between?

From a practical standpoint, what counts most are the commitments that have to be made soon. The region will have to live with the consequences of those commitments for many years, whatever future unfolds. For the period of the Action Plan, 2005 through 2009, there are relatively few commitments that need to be made: development of conservation and demand response, regardless of the specific plan, and, in the case of the lower risk plans, being prepared to begin construction of 425 megawatts of gasified coal generation by 2012. This would require beginning preconstruction activities in 2009. However, while the costs of pre-construction activities for coal-fired generation are small relative to the total cost, they are not negligible. For this reason and the fact the Act requires that the Council develop a 20-year plan, the Council believes it is necessary to choose a single plan, recognizing that future Councils will have to opportunity to revise and change that plan.

In choosing a specific plan from among those on the efficient frontier, there are a number of considerations that are not captured in the simple measures of expected cost and risk. They include

- Insurance value
- Monetary costs not associated with the power system
- Non-monetary effects not captured in the cost and risk measures
- Resource adequacy/reduced exposure to high market prices
- Effects on retail rate volatility

[1] If commercialization of gasified coal generation does not advance as expected, it may be necessary to begin construction of 400 megawatts of conventional pulverized coal steam generation as early as 2010.

Insurance Value

The way we think about power industry risk differs from how we think about power system cost and even from how we think about pure finance risk. Insurance is a money-losing proposition for the purchaser, from the standpoint of expected cost. Risk aversion, the recognition that we do not have perfect foresight and may find ourselves in bad circumstances, compels us to pay a premium to avoid or lessen the impact of some of the unpleasant outcomes due to bad situations. We might refer to the difference between the expected value and what we would be *willing* to pay as the insurance value of the premium.

The risks of a system as complex as a power industry are more diverse and complex than those of financial instruments. Adverse political impact, economic disruption, reliability issues, and power cost volatility are several examples of risk measure that dollar amounts do not capture.

The $TailVaR_{90}$ risk measure is a robust tool for capturing risk associated with distributions for net present value system costs for operating and expanding the power system, as explained in the previous chapter. Because it is denominated in dollars, however, some decision makers may be tempted to compare the value directly to cost. This is not a valid comparison, any more than would be comparing a reliability measure to a cost measure or comparing the expected payout of an insurance policy to the premium. Cost and risk measure distinct attributes of the decision.

As just stated, for complex systems the distribution of costs does not tell the whole risk story. This chapter next describes consideration of other sources of costs and risk.

Monetary Costs Not Associated with the Power System

The risk measure used in the analysis captures the power system costs associated with the high-risk futures. It does not, however, capture the non-power system costs that result when the effects of high power costs ripple through the economy.

Non-Monetary Effects

The futures that tend to be in the extreme high end of the distribution of costs are the ones with very high market prices and insufficient resources to avoid those prices. The risk measure captures those cost differences between plans, but they do not reflect the social and political disruption that accompanies periods that accompanies short supplies and high prices. Nor do they reflect fully the environmental costs that can accompany short supplies and the need to run relatively inefficient generation or curtail hydroelectric operations for fish mitigation. Those are reasons to give higher weight to lower risk plans.

Resource Adequacy and Market Prices

The portfolio model is not a reliability model. However, it can provide indications of relative resource adequacy. Analyses carried out using GENESYS, the Council's reliability model indicate that the region can maintain a 5 percent loss of load probability with an annual critical water deficit of somewhat over 1,000 average megawatts if it can count on imports of 1,500 megawatts of imports across the winter season (Chapter 8). Assessments of the likely seasonal availability of resources in the Western System suggests this amount should be available, given the seasonal load diversity that exists between the Northwest and the Southwest.

Based on this assessment, the portfolio model has been used to assess the frequency across all the futures with which market purchases in excess of 1,500 megawatts are made when prices are high (greater than $100 per megawatt-hour). These are purchases that generally would not be made unless it was necessary because most regional resources have operating costs less than $100 per megawatt-hour. Figure 7-4, compares the percentage of futures in which such purchases are made for the least cost

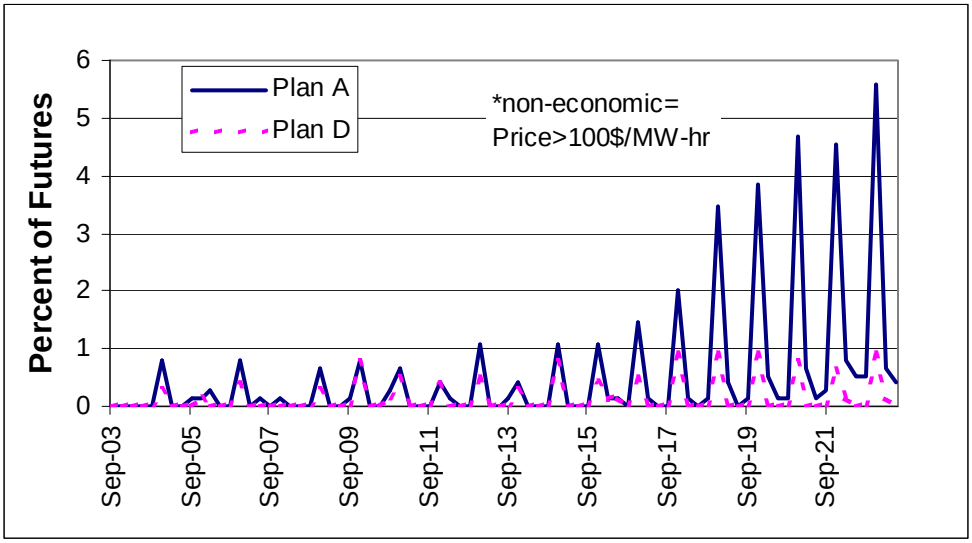


Figure 7-4: Frequency of "Non-Economic" Imports

and least risk plans (A and D, respectively). Both are identical in the early part of the planning period as no resources other than conservation and demand response are developed then. In the later years, the lack of additional resources in the least cost plan cause the incidence of non-economic purchases to increase significantly relative to the least risk plan.

Related indicators of relative resource adequacy are the market prices for different plans. If market prices are high and there are sufficient regional resources to meet regional loads, market prices will be driven down to the operating cost of the most expensive regional resource that has to dispatch to meet load. As indicated by Figure 7-5, average market prices for the least cost and least risk plans begin diverging early in the next decade with the least cost plan experiencing considerably higher market price s later in the planning period.

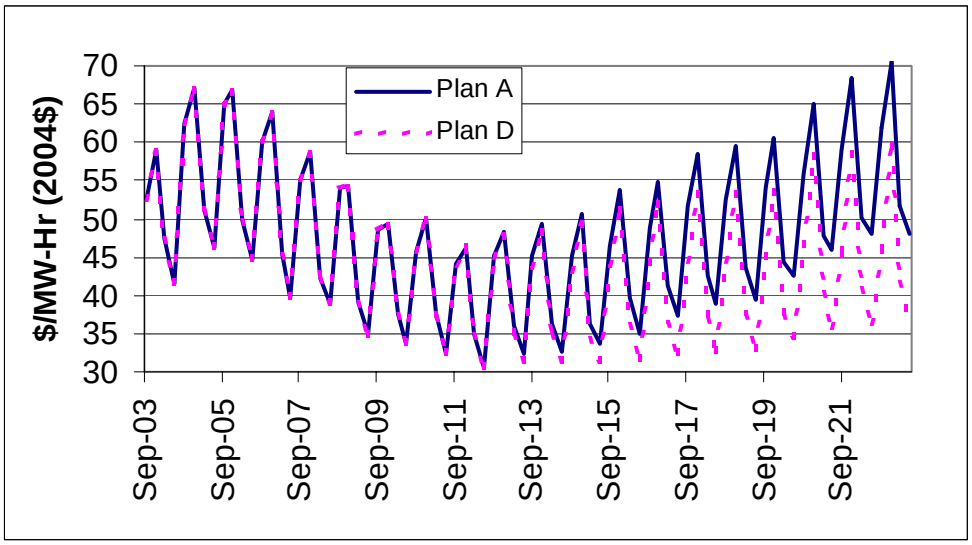


Figure 7-5: Average Quarterly On-Peak Electricity Market Prices

Retail Rate Increases and Volatility

Retail rate increases and volatility are also of concern. Indicators of retail rate impacts were developed. One indicator is a proxy for the increase over first year retail costs.[2] Figure 7-6 shows the percent of futures experiencing increases over first year retail costs of various percentages for the four different plans. As you would expect, moving toward the least risk plan (D) reduces the frequency of cost increases of any level.

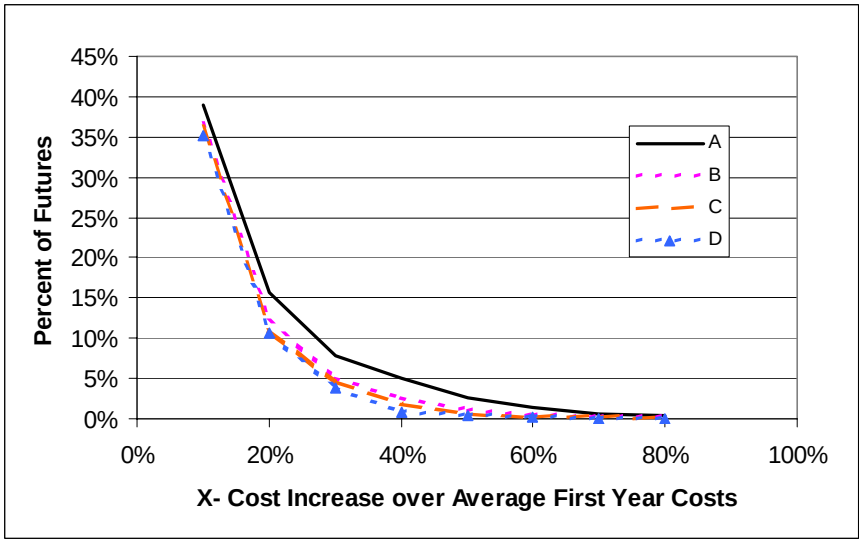


Figure 7-6: Percent Futures with Retail Cost Increases (over First Year Retail Cost) Greater than X

[2] The estimates of retail cost increases take into account the estimated fixed costs of the existing system.

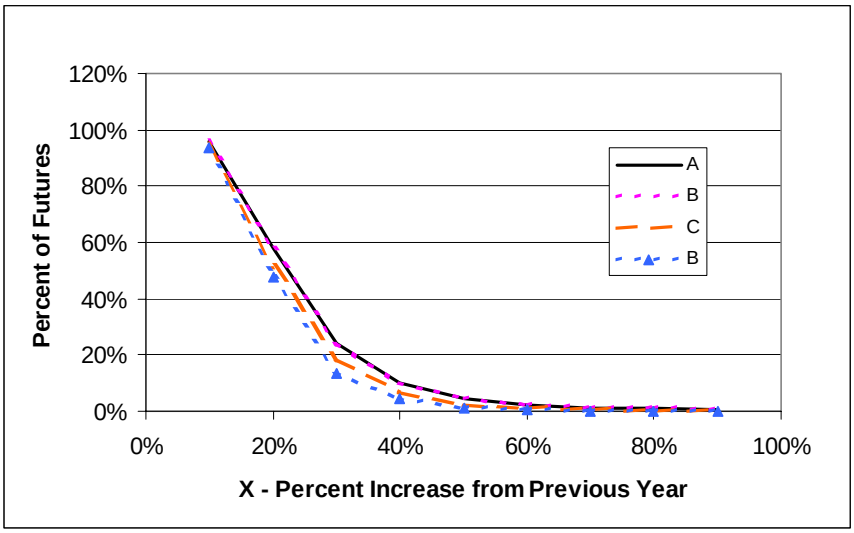


Figure 7-7: Percent Futures with Year-to-Year Cost Increases Greater than X

Year to year retail price volatility is also of concern. Figure 7-7 shows the frequency of year-to-year percentage cost increases as a proxy for retail rates for the different plans. Again, the lower risk plans exhibit less volatility. For example, the least risk plan is about half as likely to experience year-to-year retail cost increase of 30 percent than the least cost plan.

Choice – the Least Risk Plan

The foregoing considerations all support the choice of a lower risk plan. This choice is made easier in that choosing one of the lower risk plans has relatively little cost during the action plan period compared to the higher risk plans. Those additional costs are part of the pre-construction costs for 425 megawatts of gasified coal generation and 100 megawatts of wind. The Council and the region will have the opportunity to re-examine the commitments to most of the generating resource decisions in light of additional information.

How Much Conservation?

The analysis up to this point incorporated estimates of the achievable rates of conservation development that, based on analysis and past experience, the Council believes to be doable though aggressive. But would a lower rate of conservation development be less costly or reduce risk?

To answer that question, three different options for conservation development were analyzed:

- **Option 1** (the base case)
  - Non-lost opportunity conservation was limited to a maximum rate of development of 30 megawatts a quarter or 120 megawatts per year. This is representative of the levels the region has achieved in the early ‘90s and

again in 2001 and 2002. It has not, however, achieved this level on a sustained basis.

- Lost opportunity conservation was limited by a 12-year phase-in. This is representative of, for example, the time between the Council adoption of the original model conservation standards and implementation by state and local governments with jurisdiction over the majority of the new construction in the region.

- **Option 2**
  - Non-lost opportunity conservation was limited to a maximum rate of development of 20 average megawatts per quarter or 80 average megawatts a year. This is representative of the level of development in many years but well short of the maximum that has been accomplished.
  - Lost-opportunity conservation was limited to the same 12-year phase in used in Option 1.
- **Option 3**
  - Non-lost opportunity or discretionary conservation limited to a maximum rate of development of 10 average megawatts per quarter or 40 average megawatts per year. This is close to the lowest rates of conservation development experienced over the last 20 years.
  - Lost opportunity conservation was assumed to require a 20-year phase in before the available potential could be developed to its maximum achievable level (85 percent of the cost-effective potential). This is longer than it took to incorporate the model conservation standards into state and local codes or to improve the efficiency standards for new appliances.

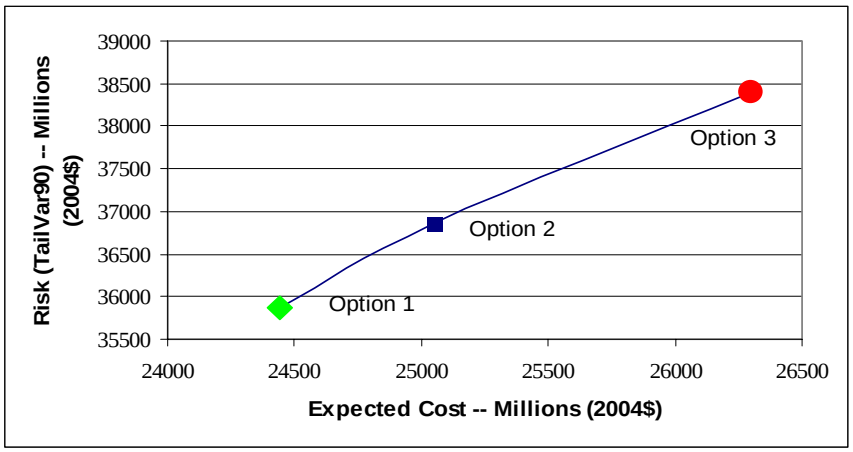


Figure 7-8: Cost and Risk of Least Risk Plans for Alternative Conservation Strategies

Figure 7-8 shows the cost and risk values for the lowest risk plans along the efficient frontiers for the three options analyzed. It is clear that the more aggressive level of conservation results in both much lower expected cost and risk. The differences in expected cost and risk between options 1 and 2 are roughly $700 million and $1 billion, respectively. The differences between options 2 and 3 are much greater. Under Option 1, expected value system cost is $1.8 billion lower and the risk is $2.5 billion less than under Option 3. The conservation derives some value by being in place when periods of high prices occur. This means that higher levels of development in the earlier years of the planning period

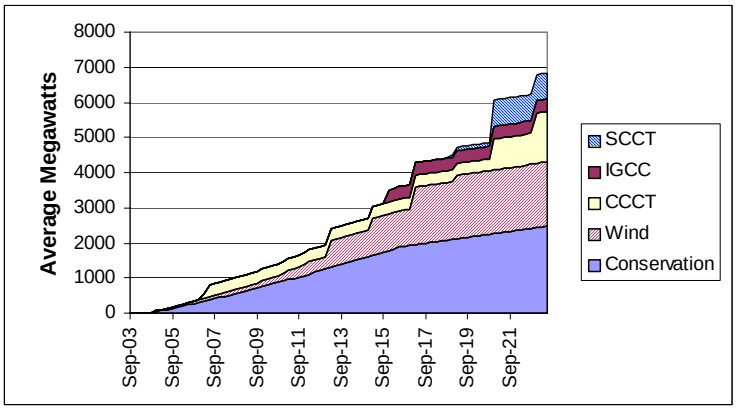


Figure 7-9: Representative Development -- Option 1: Base Case Conservation Development

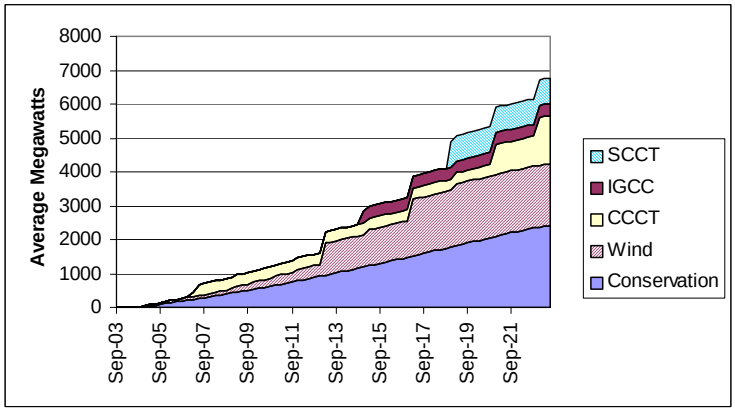


Figure 7-10: Representative Development -- Option 2:Reduced Near-Term Conservation

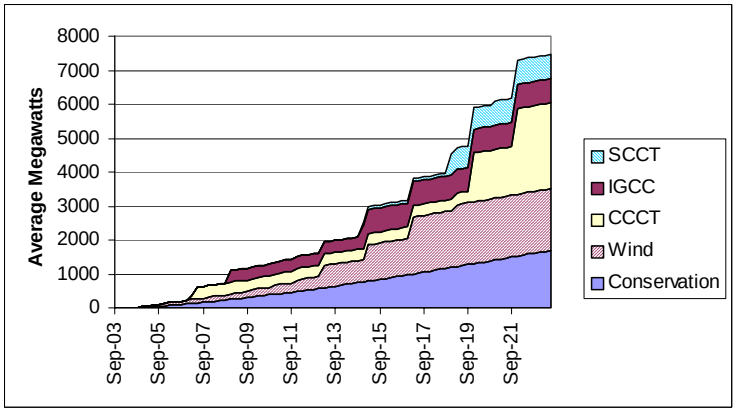


Figure 7-11: Representative Development -- Option 3: Restricted Conservation

are justified. If the region waits for high prices to hit, there isn't time to get the conservation in place. This was one of the lessons of 2000-2001. Because the conservation is low cost compared to the alternatives, it has value, even when prices are relatively low.

The rate of conservation development also affects the need for other, more expensive resources, as illustrated in Figures 7-9 through 7-11.

Comparing Figure 7-9 (Option 1) with Figure 7-10 (Option 2) shows that the modest reduction in the rate of conservation acquisition over the next few years requires moving development of generation resources forward. Wind development is advanced two years and the development of the gasified coal generation is advanced a year. Development of single cycle combustion turbine units is also advanced two years. As a consequence, there is greater development of gas-fired generation in Option 2, exposing the region to higher gas price risk.

Option 3 (Figure 7-11) reflects significantly reduced conservation acquisition throughout the planning period. This requires advancing the development of the virtually all the generating alternatives.

On the other hand, the accelerated development of conservation in Option 1 provides the region with more time to assess whether the commercialization of gasified coal generation is advancing as expected, to decide when and if to commence construction of

new coal generation, and to take advantage of anticipated reductions in wind resource costs. Earlier conservation development allows the region to defer decisions on generating resources -- decisions that bear relatively greater risks given the uncertainties the region faces. Compared to generating resources, conservation is a low-cost and low risk way to maintain an economic reserve margin.

Based on the forgoing analysis the Council recommends that regional target for development of 700 average megawatts of cost-effective conservation over the next five years (Option 1). This includes about 600 average megawatts of non-lost opportunity conservation and about 100 average megawatts of lost opportunity conservation in the average build out. Specifically, the Council recommends that the region increase the pace of conservation acquisitions from 130 average megawatts in 2005 to 150 average megawatts in the 2009. It also recommends that the region continue to modestly increase the rate of cost-effective lost-opportunity conservation acquisition in the following years. The Council's regional conservation targets can and should be achieved through the acquisition of regionally cost-effective savings.[3]

The Council reviewed the range of conservation acquisitions in the first five years of the planning period over the 750 futures tested to get a sense for the consistency of the 700 average megawatt near-term targets. Both levels of economic growth and the forecast market price of electricity affect how much conservation is developed in any future.[4] That review shows that for non-lost opportunity conservation, there is almost no variation in conservation acquisition rates in the first five years. The model finds that costs and risks are lowest if discretionary conservation is deployed at the maximum level of 120 average megawatts per year. For lost-opportunity conservation, there is a narrow range of conservation deployed over all the futures depending primarily on economic growth conditions and the apparent market price of electricity in each future. In 70 percent of the

[3] The determination of whether a particular conservation measure or program is regionally cost effective should no longer be determined by comparing it to a single maximum "levelized life cycle cost" because the *value* of a measure's savings depends on the time of day and season of year that those savings occur. A measure or program's cost-effectiveness should be based on whether the discounted present value of all of its benefits, including quantifiable non-energy/environmental costs and benefits are equal to or greater than the discounted present value of all of its costs. Benefits include the value of avoided market purchases based on the load shape of the measure's savings, avoided transmission and distribution costs (again, based on the load shape and coincidence factor of the measure's savings), "O&M" cost savings, non-energy benefits (e.g. reduced water use for higher efficiency clothes washers). Costs include capital, operation and maintenance, periodic capital replacements (e.g. heat pump compressors), plus any "program administrative" cost deemed necessary to install the measure and keep it operating properly. In addition, 10 percent should be added to the avoided cost of market purchases and transmission and distribution to comply with the Act's requirement that conservation can cost up to 110 percent of the incremental system cost of the non-conservation alternative. Measures with Benefit/Cost ratios of 1.0 or better are considered regionally cost-effective. See Appendix D - Conservation Cost Effectiveness for additional detail.

[4] The availability of lost-opportunity conservation is tied to economic growth rates. In futures when the economy is slow growing, fewer new buildings are constructed and appliance replacement rates are relatively slow making less lost-opportunity conservation available. More is available in high-growth periods. Furthermore, a cost-effectiveness standard is used to determine least cost and least risk conservation targets for lost-opportunity and non-lost opportunity conservation in the portfolio analysis. The modeling recognizes that cost effectiveness levels change as estimates of the market price of electricity change. In futures where the forecast market price of electricity is low, less conservation is developed. More is developed in futures where forecast market prices for electricity are high. For further details see Chapter 6 and appendices E and P.

futures, the range of lost-opportunity conservation deployed over the 2005-2009 period is between 90 and 105 average megawatts in the least-risk plan.

The Council recognizes that the five-year 700 average megawatt targets represent an increase over recent levels of development. It in no way discounts the difficulty that regional utilities and systems benefit charge administrators will have in achieving this level. However, the Council's analysis of the potential regional costs and risks associated with developing lesser amounts of conservation demonstrates that failure to achieve this target exposes the region to substantially higher costs and risks. The Council believes that stabilizing the regional investment in conservation at this level has a much greater probability of producing a more affordable and reliable power system than alternative development strategies.

Figure 7-12 shows the Council's recommended targets by sector and resource type for the period from 2005 through 2009. It is important to note that the Council recommends that conservation resource development should be split between "lost opportunity" and "non-lost opportunity" resources.

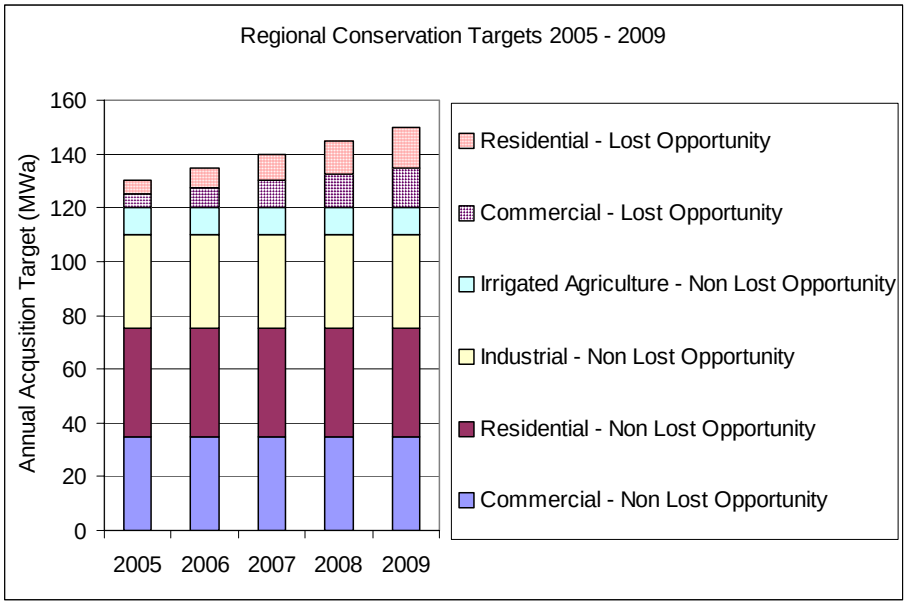


Figure 7-12

The Council estimates that the Total Resource Cost of these acquisitions over the five-year period covered by this plan is approximately$1.5 billion (2000$). The Council believes that this cost should be shared between the region's consumers and the regional power system.

Value of Demand Response

In addition to conservation, demand response develops gradually over the planning period, beginning with 500 megawatts in 2008 and reaching 2,000 megawatts by 2020. The first year fixed cost is estimated to be $5,000 per megawatt-year and the annual fixed cost to maintain the capability is estimated to be $1,000 per megawatt-year. It is dispatched only when market prices exceed $150 per megawatt-hour. Demand response is used in 83 percent of all the years examined. In most of those years it is used for only a small fraction of its capability (the equivalent of less than 89 hours per year in 85 percent of those years). In 95 percent of all years, 8 percent or less of the available demand response capability is used. But in futures with very high prices, it can be dispatched at higher levels to help moderate prices and maintain reliability. Without any demand response resources, the average cost of the least risk plan increases by almost $146 million while risk is increased by $235 million.

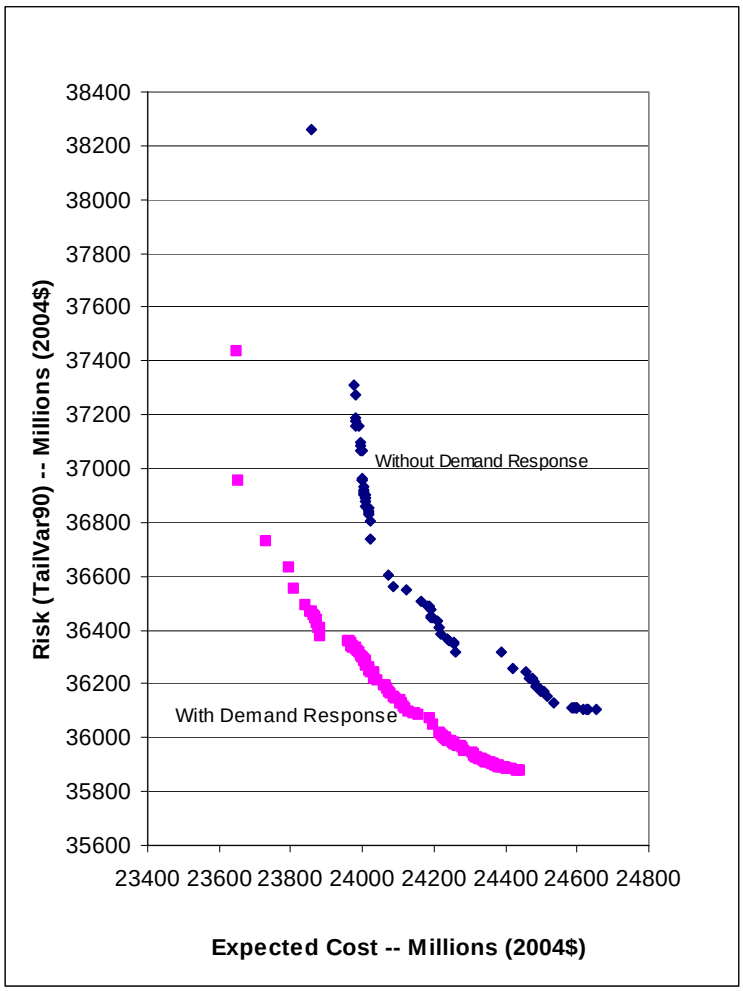


Figure 7-13: Efficient Frontiers With and Without Demand Response

Council staff compared the efficient frontiers for the base case demand response assumptions compared to the assumption of no demand response. Figure 7-13 demonstrates the effect of demand response along the efficient frontier. The loss of demand response shifts the efficient frontier up and to the right (more expensive and risky outcomes). The amount of shift varies along the frontier, but over most of the range the loss of demand response increases expected cost by about $300 to $500 million at given levels of risk. Alternatively, loss of demand response increases risk (at given levels of expected cost) by about $300 million to $500 million over most of the range.[5]. The increased costs are largely attributable to significantly more gas-fired

[5]At the upper left ends of the efficient frontiers the risk-reducing benefits of demand response increase substantially, to well over $1 billion. The plans that make up this part of the efficient frontiers depend

generation included in the plans without demand response as well as greater exposure to high market prices. The fewer conventional resources, the more valuable demand response becomes.

Appendix H presents comparisons of the cost of peaking generators and demand response, as means of meeting peak loads (and mitigating peak prices). This analysis also indicates that demand response is cost-effective.

The amount and cost of the demand response resource are somewhat uncertain. For this reason, it is important to begin work on the resource now. The Action Plan describes in a number of specific actions needed to make sure that demand response is available to make its contribution to the region's power system.

GENERATING RESOURCE DEVELOPMENT

No regionwide need for major generating resource development before 2010

From an aggregate regional standpoint, new generating resources are unlikely to be needed for the remainder of this decade. An important factor driving this finding is the current surplus of generating capacity. This surplus is to a large extent a result of the price excursions of 2000 and 2001. High prices led to a substantial loss of regional load and to construction of over 4,200 megawatts of new generating capacity in the region. Loads have yet to recover to 1999 levels, leaving much generating capacity underutilized. Even at forecast medium-high rates of load growth, the current resources appear sufficient to maintain a regional load-resource balance of - 1,500 average megawatts, or better, through 2011, an amount sufficient to maintain system reliability[6]

Much of the surplus generation is not owned or contracted on a long-term basis to utilities and does not have firm transmission access to markets outside the region. While these resources can be counted on from a resource adequacy standpoint, their output will be sold at market prices. Their presence will moderate market prices but the economic benefits they earn when prices are high go to the owners, not the region (as will the losses when prices are low). Regional utilities could secure these benefits at the cost of purchasing the independent generation or entering into long-term purchase contracts with the owners. There are, however, reasons why utilities might choose instead to build new generation.

Another factor reducing the need for near-term generating resource development is the large, relatively low cost conservation potential. Conservation, moreover, is free of natural gas price and carbon dioxide control risks. Aggressive acquisition of conservation provides a lower risk, lower cost regional resource mix than alternatives substituting new generating resources for conservation.

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more heavily on purchases from the wholesale market, and demand response greatly mitigates the risks of those purchases.

[6] The Northwest can maintain reliability at a regional deficit of 1,500 – 2,000 average megawatts, assuming adequate import capability. See Chapter 8

Some cost-effective generating projects may become available prior to 2010

While the portfolio analysis does not call for generation resource development prior to 2010, opportunities for development of cost-effective smaller-scale renewable or high-efficiency generating projects that might otherwise become "lost opportunities" will likely surface prior to 2010. Examples include industrial or commercial cogeneration projects; landfill, animal waste or wastewater treatment plant energy recovery; hydropower renovations; forest residue energy recovery and photovoltaics serving small isolated loads. The opportunity to economically develop these projects is often created by needs not directly related to electric power production, such as a waste disposal issue, process or equipment upgrading or new commercial and industrial development. These opportunities should be monitored and the projects secured when cost-effective.

Because of their diversity, small-scale and site-specific nature, these types of projects were not included in the portfolio analysis. Examples of these projects are given in Chapter 5, where their levelized costs are compared to levelized forecast electricity prices. Even if these projects are not economic when evaluated on a purely levelized cost basis, they may be cost-effective when additional attributes are considered. For example, cogeneration projects may provide supplementary revenue streams and avoided transmission and distribution costs. Higher thermal efficiency reduces the exposure of these projects to fuel price and carbon dioxide risk. Likewise biomass, small hydropower, geothermal and other renewable resources offer the fuel and carbon dioxide risk reduction qualities of wind and in addition produce higher-quality, non-intermittent power. Projects using biomass residues may benefit from avoided waste disposal costs.

Peaking, emergency service, hydrofirming capacity and non-wires generating alternatives to transmission are among the other types of projects that may become cost-effective prior to the end of the decade.

Coal and wind power plants appear most attractive resources when new bulk power supplies are needed

The relatively low cost of coal, natural gas price uncertainty and the probability of some level of carbon dioxide control costs during the planning period lead to the preference for gasified coal generation in the mid-term. The plan calls for being prepared to bring 425 megawatts of gasified coal into service by 2016. Construction lead-time requirements are such that the region should be prepared to begin construction of this capacity by the beginning of 2012. This would mean that siting, permitting and other pre-construction activities would need to commence by early 2009.

While the analysis found the development of gasified coal generation to be lower cost and lower risk, this conclusion is predicated on continued commercialization of gasified coal technology. If commercialization fails to advance as estimated and other estimates underlying the plan do not change significantly, 400 megawatts of conventional coal-fired capacity could be needed by 2013. This would require preconstruction development to commence by mid 2007 so construction could begin as early as 2010.

Forecasted continued cost reduction, and absence of fuel price and carbon dioxide risks support the attractiveness of windpower in the longer-term. The short construction lead-

time of wind projects reduces the probability of prolonged exposure to wholesale price excursions. The least-risk plan calls for being prepared to begin construction of at least 100 megawatts of new wind power capacity by 2010, with increasingly larger amounts thereafter.

Assumptions regarding continued cost reduction appeared to be an important factor leading to the prominence of wind in the later years of the preferred plan. Technological improvements and economies of scale are assumed in the base case to lead to an annual average cost reduction of about 2 percent from 2004 through 2025. To test the importance of this assumption, a sensitivity test was run with no improvement in windpower cost. This test, in addition to representing the effects of wind plant cost reduction, also serves as a proxy for other uncertainties that bear on cost including higher than expected shaping or transmission integration costs, lower quality wind resources, site development limitations or lack of financial incentives. Holding wind costs constant increased both the overall cost and risk for comparable plans. However, resource development schedules did not change appreciably: the timing and amount of coal and the timing of wind remained as in the base case. These results indicate that while the benefits of wind are sensitive to the cost of the resource, wind is likely to remain a valuable resource even without appreciable cost reduction, given our current understanding of the cost of other generating alternatives. However, reductions in the costs of some of those alternatives, e.g. Alberta oil sands cogeneration, could alter that conclusion. This reinforces the importance of the preparations for windpower development called for in this plan.

Assuming that uncertainties are reasonably characterized in this analysis, the quantity of resource options needed for a given year, other factors equal, will decline over time as uncertainties for a given year decline. Capacity actually needing to be constructed is likely to be less than the amount of options called for here.

Uncertainties regarding large-scale development of wind power need to be resolved

The portfolio analysis indicates that large-scale windpower development will provide significant cost and risk reduction benefits to the Northwest. This assumes a large high quality developable resource, continued cost reduction and technology improvements, relatively low shaping and firming costs, the ability to extend transmission service to promising wind resource areas and a robust wind development infrastructure. The Council has assumed that large quantities of wind will be available despite uncertainties regarding these assumptions because of the benefits wind can provide to the regional power system.

Because the plan does not call for wind power before the end of the decade, time is available to resolve uncertainties and to prepare for large-scale development. The most effective approach to resolving uncertainties associated with large-scale deployment of wind generation appears to be through moderate development of commercial-scale pilot wind power projects at a diverse set of wind resource areas. These projects, properly developed, can confirm the development potential of additional wind resource areas through wind resource assessment, assessment of environmental issues and planning for transmission and other infrastructure requirements. These projects can facilitate the

monitoring of cost and performance trends and provide information supporting assessment of the cost of shaping large amounts of wind energy, including the possible benefits of geographic diversity. These projects can also provide data for improving the understanding of the capacity value of wind and can serve as vehicles for securing the environmental assessments and permits needed for full development of the wind resource areas where they are located. Finally, the projects will help maintain and strengthen regional wind development infrastructure.

Some of these objectives could be achieved at lower cost through the non-construction research and development activities advocated in the Council's 1991 plan. In practice, resolution of wind power uncertainties through research and development projects has proven difficult because of the structure of the windpower industry.

Development of 500 megawatts of wind capacity composed of projects of 50 to 100 megawatts over the next 5 years would resolve these uncertainties. This is consistent with the announced plans of several Northwest utilities and system benefits charge administrators.

The Council believes that interest within the utility community exists to support the level of wind development needed to resolve uncertainties. It is less clear that utilities and project developers are prepared to fully utilize these early projects as laboratories for resolving uncertainties associated with large-scale wind power development. The Council, working with Bonneville, utilities, SBC administrators, applicable state agencies, the wind industry and other stakeholders will convene a forum to develop a strategic plan for accomplishing this objective.

Oil Sands Cogeneration

A 2,000-megawatt DC intertie from the oil sands region of Alberta to the Celilo converter station at The Dalles has been proposed to open a market for oil sands cogeneration. The transmission could be energized as early as 2011. Preliminary estimates suggest that power from oil sands cogeneration could be delivered to the Northwest at a levelized cost of $41 per megawatt hour, slightly lower than the comparable cost of electricity from a new gas fired combined cycle plant in the Mid-Columbia area. The higher thermal efficiency of oil sands cogeneration may offer better protection from natural gas price volatility. Further protection from gas price volatility could be secured by operating the cogeneration plants on a synthetic fuel gas derived from residuals of oil sands processing. Because the incremental carbon dioxide production of cogeneration is less than that of stand-alone gas-fired generation, the cogeneration proposal would also be less sensitive to the cost of carbon dioxide control measures. Because of uncertainties associated with construction of needed transmission, oil sands cogeneration is not considered an "available" resource as defined by the Regional Act. A sensitivity test was run, however, to explore the benefits of the resource. For this analysis, power was assumed to become available in blocks of 200 megawatts capacity. While it is not clear that the output of the proposed project could be secured in such small increments in practice, the study may indicate the optimal timing and rate of acquisition if the project is competitive with other resource options.

Results of the sensitivity analysis were inconclusive. System risk was reduced, but with a slight increase in cost. Because oil sands cogeneration appeared in plans near the least-

cost plan but not in any plan along the efficient frontier, it was not apparent that the reduction in risk was attributable to oil sands cogeneration. Assessment of the oil sands cogeneration will continue following release of the draft plan. It is apparent that the large unit size of the proposed 2,000-megawatt transmission intertie and the long development lead-time (seven years, controlled by transmission development and construction) are barriers. Options for staging development and reducing lead-time have been discussed with the project developer and will be further explored.

Individual utility situations may differ

Though no large-scale generating resource development appears to be needed this decade on a regionwide basis, the circumstances of individual utilities may be such that the near-term development or acquisition of new generating resources may be necessary. Some utilities may be in resource deficit, having experienced more rapid load growth than the regional average or having not lost load to the extent of the regional average. The conservation potential available to some utilities may be insufficient to meet near-term loads. A utility may have been purchasing a major portion of supply on short-term contract, and may find it desirable to increase the amount of generation owned or on long-term contract. Some of the recent requests for proposals for generation may be attempts to secure such supplies at the lowest cost. Finally, some utilities may need generation for peak period capacity, emergency generation needs, hydrofirming capability or system reinforcement. Any of these situations may result in an individual utility needing to acquire generating resources before regionwide needs are present.

Likewise, the preferences for coal and wind power are based on the overall regional situation and may not be suitable for all utilities. A utility may already have a large amount of coal-fired capacity and not wish to extend climate change risk. Climate change risk, though very important in arriving at the recommendations of this plan, is very uncertain, and a utility may have a different view of the magnitude or timing of climate change risk, leading to different valuation of resource qualities. Finally, because of its geographical situation, an individual utility may have different resource choices than considered here, or the cost of resources may differ from the assumptions used here. For any of these reasons, the resource choices of individual utilities may differ from the recommendations of this plan.

Carbon Dioxide Emissions Mitigation

A major uncertainty facing the utility industry is the likelihood, timing and magnitude of measures to reduce the emissions of carbon dioxide, a greenhouse gas implicated in global climate change. This is important because of the impact that carbon dioxide control costs would have on comparative cost of new generating alternatives. This is illustrated on Figure 7-15. This figure shows the bus bar cost of power (not including transmission) as a function of carbon dioxide control costs. The underlying assumptions include identical financing, 2010 operation and fuel prices corresponding to the medium forecast. In the case of wind, estimated costs of shaping output to load are included. With the exception of wind and coal gasification with carbon sequestration, the costs of power are very sensitive to carbon dioxide control costs.

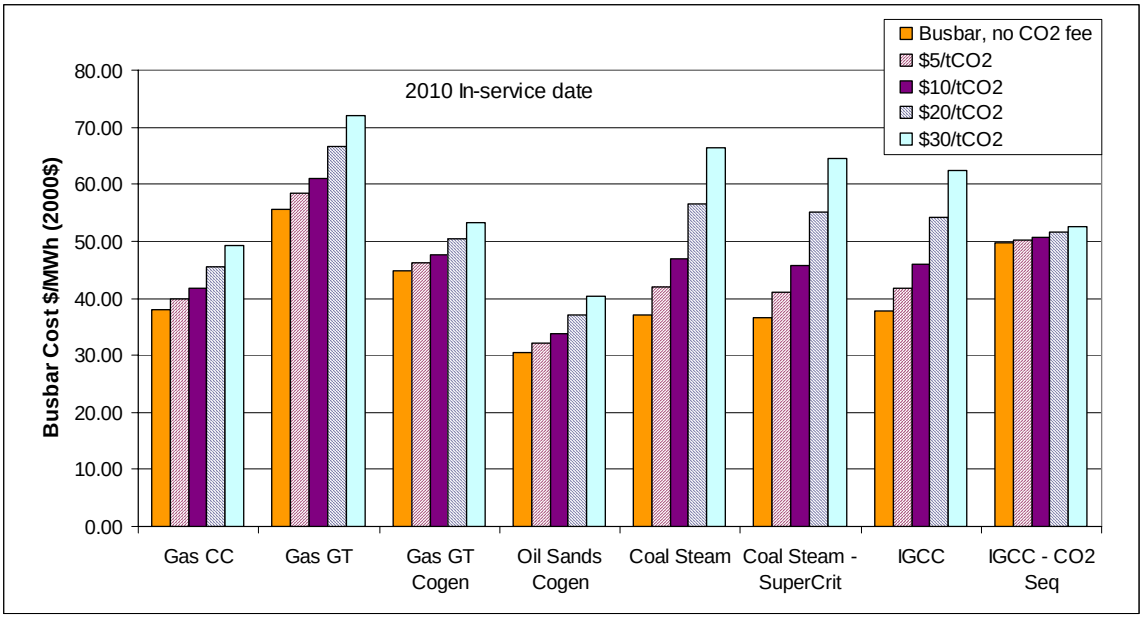


Figure 7-15: Effect of Carbon Taxes on Bus Bar Cost of Power for Alternative Generation Technologies

As further discussed in Appendix M, there is a growing expectation that some penalty will eventually be imposed on carbon emissions, either by a cap and trade system similar to that established for oxides of sulfur and nitrogen (the currently favored approach) or by carbon tax as earlier proposed. However, there is little agreement about when and how much. .

For this analysis we have treated a wide range of outcomes for climate change policy as equally probable. For modeling purposes we have assumed a tax, though the effects of a cap and trade system would be similar. We have modeled a carbon tax ranging from zero to $15 per ton of carbon dioxide emissions beginning a early as 2008 and with the possibility of change every 4 years. The level can increase to as high as $30 per ton carbon dioxide beginning in 2016. Thus some futures will have no carbon tax; some will have $15 per ton beginning in 2008, some will have $30 per ton beginning in 2016 and the rest will represent other possibilities between those extremes. By the end of the planning period, roughly two thirds of the futures have some level of carbon tax. This is illustrated on Figure 7-16. The $30 per ton carbon dioxide is estimated to be roughly comparable to the effect of a cap and trade system proposed in the McCain-Lieberman bill.[7] As this figure illustrates, the probability of a relatively significant carbon control cost increases with time. As a likely consequence, the portfolio model has no coal

[7] *Emissions Trading to Reduce Greenhouse Gas Emissions in the Unitied States: The McCain-Lieberman Proposal*, MIT Joint Program on the Science and Policy of Global Change, Report No. 2007, June 2003. p. 17

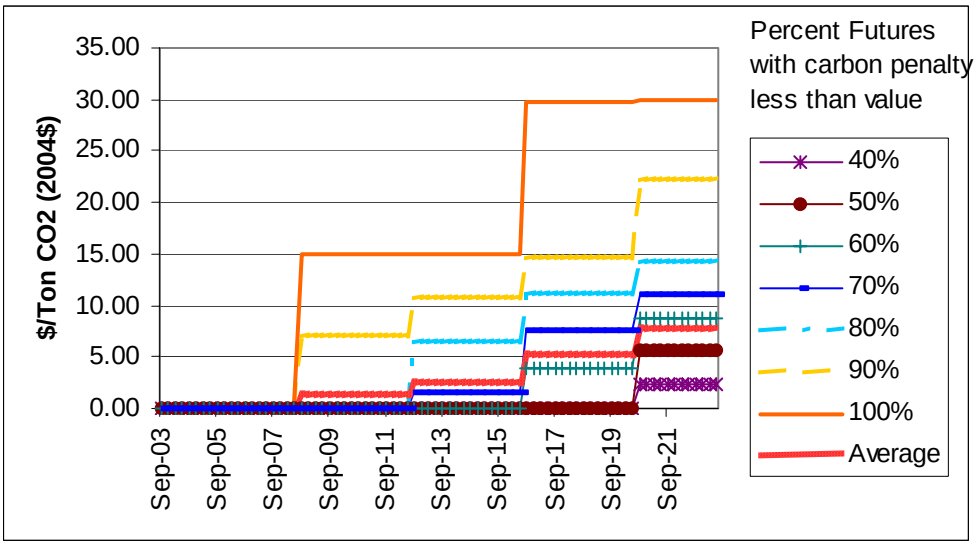


Figure 7-16: Probabilistic Representation of Future Carbon Penalty

generation coming into service after 2017 in any future. A sensitivity test was run with a single carbon tax scenario similar to that used in some utilities' integrated resource plans. This began at $4 per ton of carbon dioxide in 2010, rose to $9 per ton in 2012 and continued to rise linearly to about $12 per ton by the end of the study period. The plans produced with this assumption were not markedly different from our base assumptions. However, it is likely that more significant carbon control measures implemented earlier in the planning period could have a more significant effect. This makes monitoring the state of climate change science and policy important as future resource decisions are made.

Direct Service Industries Loads

Once source of uncertainty is the loads of the Direct Service Industries (DSIs), primarily aluminum smelters. For the bulk of the analysis in this plan, DSI load has been modeled as a function of the market price of aluminum and the market price of electricity as described in Appendix A. Implicit in this is the assumption that DSIs will purchase all their power on the market and will not receive any power from the Bonneville Power Administration at a rate linked to Bonneville's average system cost. This is consistent with the current situation but is at odds with most of the DSI's history in the region. With this assumption, there are only 20 percent of the futures in which some DSIs operate. Over all the futures, the DSI load averages less than 100 average megawatts. There are, however, proposals to provide some amount of power to DSIs at a rate tied to Bonneville's average system cost or an equivalent monetary incentive. If such an incentive were to have a large effect on DSI loads, it could require accelerating resource development.

There are a number of ways in which incentives for DSIs could be structured. For this sensitivity analysis, we have based the incentive on the proposal put forward by the Joint

Customers of Bonneville in 2002.[8] Each of the seven remaining smelters may purchase up to 100 megawatts of power from Bonneville at a rate of $31.35 per megawatt-hour. This corresponds to Bonneville's priority firm rate, incorporating the recently announced 7.5 percent rate reduction.

The incentive does increase the frequency with which higher DSI loads are observed as well as the average DSI load. But the effect is relatively small. The effect on expected cost and risk is to increase expected cost and risk slightly. The resource plan is affected to a small degree. There are, however, a number of different ways in which a DSI incentive might be structured, some of which could have a greater effect. If such a policy is enacted, the final form should be evaluated for its effect on the plan.

Scenarios

While it is useful to examine a representative resource "in-service" schedule for the plan, that particular schedule is not likely match what will happen in any particular future that is actually realized.[9] That is why it is also useful to see how the plan would be implemented under different situations. Scenarios describe how the plan will manifest itself for particular futures. This section examines various scenarios and looks at the resources that would be acquired and the costs that would be incurred by implementing the plan under several different futures.

"The plan" selected, out of the thousands that were analyzed, was chosen because it was the lowest cost, lowest risk plan for the region. But minimizing risk does not mean that the plan protects the region from experiencing a bad outcome -- it only minimizes the magnitude of the bad outcomes. The primary measure of a bad outcome is very high cost. So it is important to understand what conditions lead to bad outcomes as well as what conditions lead to good and average outcomes.

It is also important to understand the strengths and limitations of the analytical approach used in developing the plan. There is no such thing as perfect foresight. The best the portfolio model can do is to identify the plan that, on average, over all the futures evaluated, results in the lowest average cost for a given level of risk. For example, using our current assumptions regarding future uncertainties and looking over all the futures, the model discovered that it is less costly overall to delay preparing to build additional gas-fired power plants until late in the planning period. Given current perceptions of gas prices, that is a reasonable conclusion. However, if a future unfolds where gas prices are consistently low (perhaps the consequence of the discovery of major new gas fields), the current plan cannot take advantage of it except to the extent existing gas-fired generation captures that value. But by monitoring gas price trends and projections, the region can assess whether the assumptions that went into the development of this plan are still valid. If they are not, then the plan must be revised to take into account this new information. The plan must be constantly reviewed and revised as our knowledge and perceptions of the possible futures change.

[8] The Joint Customers represent publicly owned and investor-owned customers of Bonneville. Their proposal can be found at http://www.nwcouncil.org/energy/bparole/jointproposal2.pdf .

[9] The "in-service" schedule is the schedule of when new resources enter service.

In order for the region to benefit from the plan, it must be ready to develop specified resources as early as the schedule calls for. But as he future unfolds, some resource development may be delayed or deferred depending on conditions. The plan does adapt to a future as it unfolds. Decisions to build resources are based on attempting to maintain a desired load-resource balance while considering the relative cost of resources. The model bases those decisions on forward projections of loads and resources, fuel prices and electricity prices. However, because there is no perfect foresight, the model makes these projections based on the past few years it has experienced in a particular future. As a consequence, it can be "fooled" by a downturn or upturn in demand or prices. There are some futures in which the region overbuilds (resulting in higher average costs) or under builds (resulting in a greater exposure to the market and potentially greater fluctuations in price). There is imperfect decision-making in the model just as there is in real life.

Figure 7-17 shows the range of potential costs (net present value in 2004 dollars) for the plan under all simulated futures. The average cost for the plan is $24.4 billion but depending on the future, the cost could soar as high as $50 billion or be as low as about $12 billion. Fortunately, the chance of the region realizing the highest cost is quite low. But there is a ten percent chance (see Figure 7-17 below) that the cost could be $32 billion or higher. The highest ten percent of costs are averaged to yield the $TailVaR_{90}$ risk measure discussed earlier. Out of all the plans considered (over 1,000) this one had the lowest risk but even so, the range of possible future costs is still quite large.

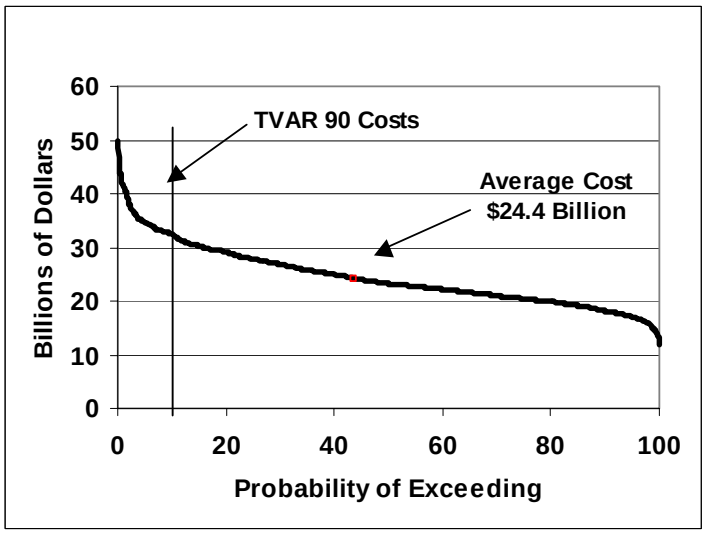


Figure 7-17: Distribution of Potential Costs

In light of this wide range of possibilities, it is important for the region to understand what kinds of future conditions lead to a high cost scenario. Recall that the major uncertain variables modeled include demand, price of electricity, price of gas and a carbon tax. By monitoring these variables over time, the region can best prepare itself to adapt the plan, if necessary, to keep costs as low as possible and maintain a reliable power supply.

For this plan, the first two scenarios examined yield the highest and lowest cost futures. Figure 7-18 illustrates the demand growth over the next twenty years for these scenarios. The low and high demand forecasts are also plotted in that figure for perspective. The high-cost future results in a net present value cost of about $50 billion while the low-cost future results in a $12 billion cost. One of the clear differences between these two futures is the demand growth. The high-cost future has an average growth rate of 2.3 percent compared to a 0.0 percent rate for the low-cost future. Both of these scenarios implement the same plan but the resource build schedules (also in Figure 7-18) differ significantly. (Remember that

the plan specifies the types of resources and the earliest schedule for beginning construction but the actual build pattern depends on the anticipated future as events unfold.)

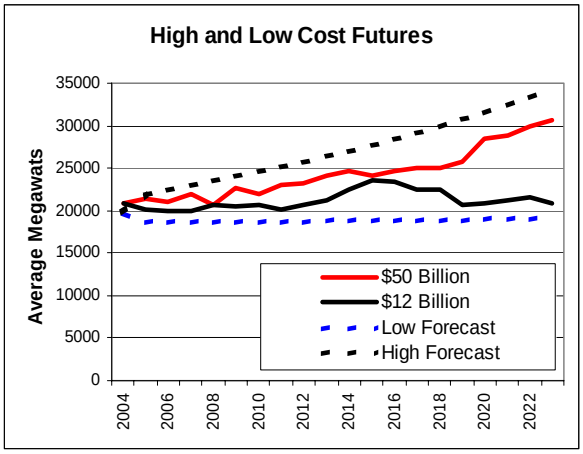
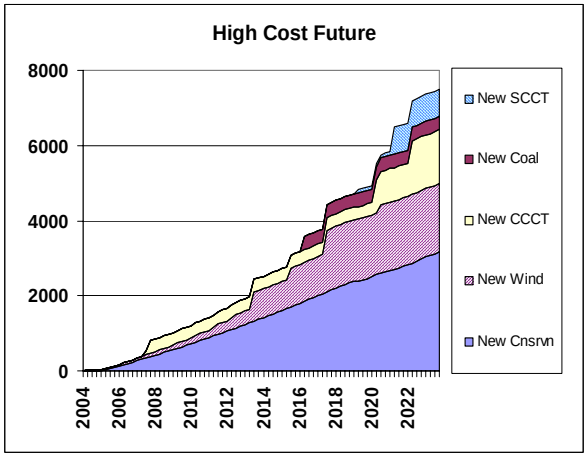
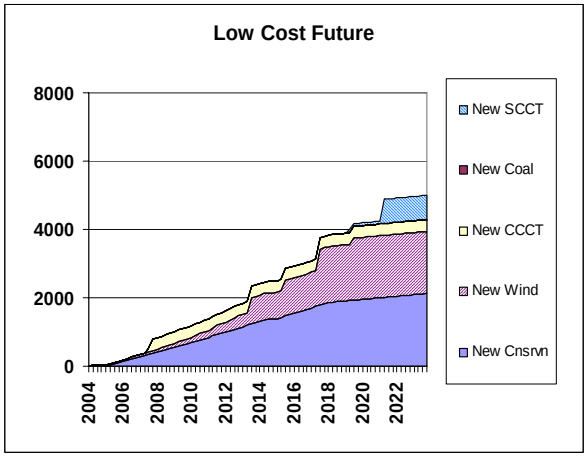


Figure 7-18:
Demand Growth for a High and Low Cost Future

Resource In-Service Schedules for a High and Low Cost Future





Average Cost - $ Billions	50
Average Growth Rate - %	2.3
Average Elect. Market Price - $/MWH	59
Average Gas Price - $/MMBtu	6.4

Average Cost - $ Billions	12
Average Growth Rate - %	0.0
Average Elect. Market Price - $/MWH	21
Average Gas Price - $/MMBtu	3.1

In the low-cost future, no coal is acquired over the study horizon. In fact, only conservation, wind and a little bit of simple-cycle combustion turbines are built. The "new CCCT" in the "Low Cost Future" chart reflects only the construction of the Port Westport combined cycle plant. In the high-cost case, more conservation, more wind and combustion turbines are built along with a gasified coal plant. Figure 7-18 illustrates the quantity and timing of new resources built for both of these futures.

Relative growth in demand is not the only difference leading to the cost disparity between these futures. In the high-cost future, the average price of electricity, over the twenty-

year study horizon, is about $59 per megawatt-hour compared to $21 per megawatt-hour in the low-cost future. The higher electricity price in the high-cost case contributes significantly to the overall cost of the system because of the region's exposure to the electricity spot market in that future. The high-cost future also has a higher twenty-year average natural gas price at $6.42 per million Btu compared to $3.10 per million Btu in the low-cost future. And, the high-cost case shows a 20-year average carbon tax of $9 per ton compared to $0.45 per ton in the low-cost case. Both of these variables also contribute (to a lesser extent) to the cost discrepancy between these two cases.

The cost of the power supply for any given future is a function of new resource development (related to demand growth), electricity and gas prices and level of carbon tax as well as other market factors that can lead to price volatility. Generally speaking under a future with high demand growth, more resources and consequently more capital costs will be required to serve new demand. This generally leads to higher costs but not necessarily in every case. If electricity prices stay low, the region may opt to purchase from the market and save the capital costs. A more detailed discussion of the relationship among these uncertain variables and system cost will be left for later.

The increased development of conservation in the high-cost case occurs because more conservation is cost-effective and because higher growth means more new buildings, appliances, and so on in which lost-opportunity conservation may be developed. Because more resources are built in the high-cost future, the region must pay higher capital costs.

Figure 7-19 shows the demand growth for two futures with similar growth but with very different costs. The difference between these two cases is the electricity price -- $69 per megawatt hour in the higher cost future and $28 per megawatt-hour in the lower cost future. In the case with the low price, the model chooses to purchase from the market and thus saves on capital costs. This is evidenced in Figure 7-19, which also shows the resource in-service schedules for both futures. When electricity prices are high the model will build available resources including coal, wind and combustion turbines to limit its exposure to the high-cost market. The high-electricity-price future results in a regional cost of $43 billion while the low-electricity-price future results in a cost of $22 billion.

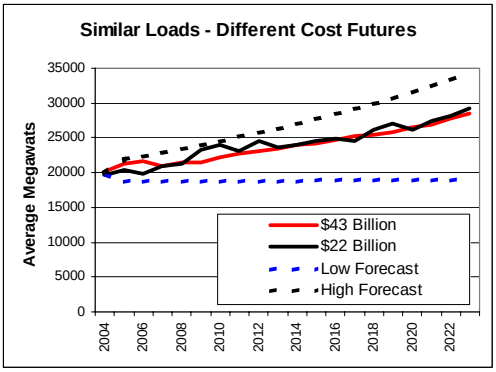
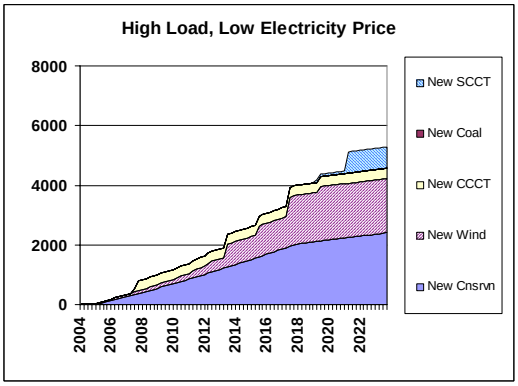
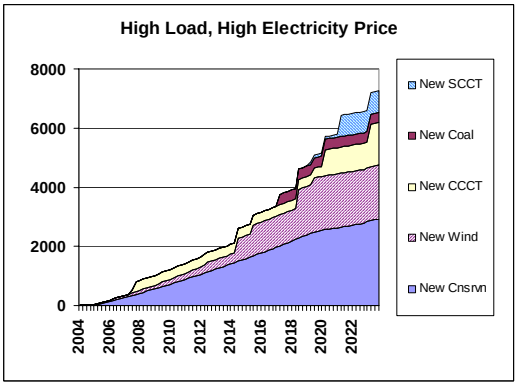


Figure 7-19:
Demand Growth for two Similar Cases with Different Costs

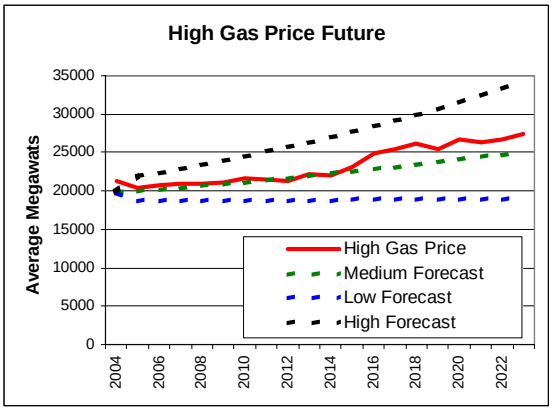
Resource In-Service Schedules for two Cases with Similar Demand but Different Costs

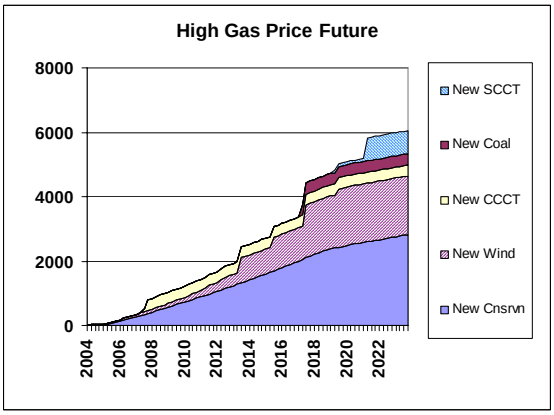




Average Cost - $ Billions	43
Average Growth Rate - %	2.0
Average Elect. Market Price - $/MWH	69
Average Gas Price - $/MMBtu	5.6
Average Carbon Tax - $/Ton CO2	4.6

Average Cost - $ Billions	22
Average Growth Rate - %	2.4
Average Elect. Market Price - $/MWH	28
Average Gas Price - $/MMBtu	4.6
Average Carbon Tax - $/Ton CO2	0.0





Average Cost - $ Billions	40
Average Growth Rate - %	1.5
Average Elect. Market Price - $/MWH	57
Average Gas Price - $/MMBtu	8.0
Average Carbon Tax - $/Ton CO2	0.0

Figure 7-20:
Demand Growth and Resource In-Service Schedules for a High Gas Price Future

Figure 7-20 shows the demand growth and the resources in-service for a future with a high gas price. For the high-gas-price case, natural gas prices average $8.04 per million Btu over the 20-year study period compared to an average gas price of $4.96 per million Btu over all futures. The demand growth for this future is very close to the medium forecast. Also, this future has no carbon tax and electricity prices are somewhat high at about $57 per megawatt-hour. Because of the high gas price and because there is no carbon tax in this future, the model chose to build coal along with wind and conservation and a few combustion turbines. This example illustrates how the plan can adapt to variations in future conditions.

Two other scenarios are examined in Figure 7-21. That figure shows the demand growth for both an early and late growth future. In the case of the early growth future, demand roughly keeps pace with the medium demand forecast through about 2012 after which it drops and stays below the medium forecast. In the late growth future, demand growth is depressed until about 2012 when it rises to about the medium level for the rest of the study period.

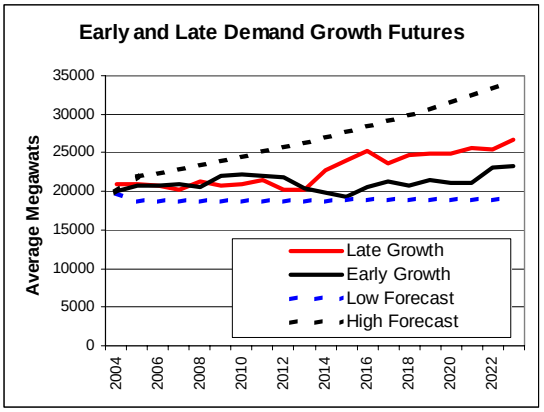
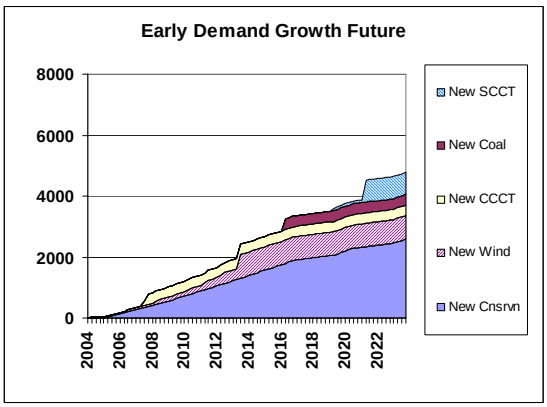
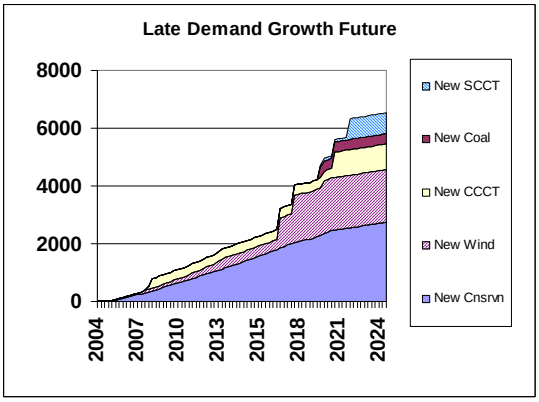


Figure 7-21:
Demand Growth for Early and Late Growth Futures

Resource In-Service Schedules for Early and Late Demand Growth Futures





Average Cost - $ Billions	22
Average Growth Rate - %	0.8
Average Elect. Market Price - $/MWH	46
Average Gas Price - $/MMBtu	4.9
Average Carbon Tax - $/Ton CO2	3.5

Average Cost - $ Billions	28
Average Growth Rate - %	1.3
Average Elect. Market Price - $/MWH	58
Average Gas Price - $/MMBtu	5.9
Average Carbon Tax - $/Ton CO2	4.1

The resource in-service schedules for these two futures are also shown in Figure 7-21. For the early-growth future, the model anticipates continued demand growth and subsequently initiates the construction of coal-fired and wind generation early in the study period. When demand drops off later in the study period, few other resources are required. This is a case where projected future growth did not materialize and the region was left overbuilt for a period. This is similar to what actually occurred in the late 1970s and early 1980s.

In the late-growth future, also shown in Figure 7-21, both the coal and wind are developed but much later. Gas-fired turbines are also built later in the study period. Build decisions in the model are initially based on the anticipated balance between

demand and resources and then on the relative cost of the resources available to meet the anticipated demand.

At the risk of stating the obvious, the better future demand growth can be forecasted and the shorter the lead times for the resource alternatives, the better the region can adapt the power supply to meet its needs. In the case of the future with late demand growth, the short lead-time of wind and the declining cost of wind generation technology lead to a substantial build of that resource. For these two futures, the timing and shape of demand growth seem to be the primary factors in determining the resource builds.

The region should plan on monitoring all of the major uncertain future variables in order to be best prepared to maintain a low cost and reliable power supply. All of these variables -- demand growth, electricity price, natural gas price and carbon tax -- could affect the resource build decisions that would be made under this plan. And if future trends or projections for these variables are discovered to track outside of the initial assumptions regarding their possible future values, the plan should be revised.

INTERPRETING THE PLAN

The plan lays out the amount, types and timing of "insurance" the region should acquire to minimize the cost for a level of risk, given the future uncertainty the region faces. The insurance is to protect the region from shortages of electricity supply, from price volatility of electricity or generating fuels, uncertainties about future environmental policies, and other potential risks. That insurance takes two forms. The first is actual resource implementation to take place during the Action Plan period. In this plan, the 5-year Action Plan is primarily focused on developing conservation and demand response.

The second form of insurance is preparatory actions during the Action Plan and beyond so that the region can begin actual construction of additional resources by some date if conditions at the time warrant. The preparatory actions include the siting, permitting and other necessary steps. Through these preparatory actions, the region acquires options. Construction of resources can begin at the earliest dates specified in the plan or construction can be delayed or even terminated, at some cost, if conditions at the time do not support construction. The time required for the stages of construction and costs associated with those stages for the major resources are discussed Appendix I.

The portfolio model sorts through hundreds of alternative plans, each tested against 750 futures to identify the kinds, the amounts and timing of resource implementation and optioning that result in the lowest average cost over all 750 futures for each level of risk. Because the range of the uncertainties increases with time, the plan typically calls for more options later in the planning period. In reality, the region will have more information when the time comes and fewer resources may be necessary. The actual resources that are developed will depend on how the future unfolds. But development is constrained by the schedules for acquisition of conservation and demand response and the schedules of the options identified in the plan. There is no guarantee that the plan will be the best one for any individual future, just as home owner's insurance may not be the best decision if you never have any claims. However, actions that fall outside the 5-year Action Plan can and should be revisited in future plan revisions.

The Regional Perspective

In the preceding chapter, several arguments outlined the potential value of a least-cost, risk-constrained regional plan to individual load-serving entities and other market participants. At several points in this plan, however, we are careful to explain why the results of this plan would not necessarily be applicable to individual participants. Properly interpreting this plan requires keeping these distinctions in mind.

Some of the reasons individual participants would view the cost, risk, and requirements picture distinct from the view from the region as a whole are the following. Load-serving entities may

- Have local requirements that can not be met by remote resources
  - Additional peaking capacity
  - Voltage control and stability support
  - Transmission constraints
- Be prohibited from hedging their economic risk with resources that do not serve a substantial portion of their load
- Be reluctant to contract for existing, surplus capacity or energy, such as from regional IPPs
  - They may not want to take on additional fuel risk. (Most of IPP projects are gas fired.)
  - Transmission limitations may prevent accessing existing generation on a firm basis.
  - They may want to get experience with newer technologies like wind.
  - They may see financial advantages in building their own:
    - There can be financial advantages in having a physical asset as opposed to a purchase contract.
    - Investor-owned utilities may be able to reduce earnings volatility.
    - Publicly owned utilities can finance projects at lower costs.
    - Credit risk issues may make purchases from an IPP more expensive.

For these and other reasons, decision makers should view the resource construction schedule in this plan with recognition to its scope and limitation.

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Resource Adequacy

INTRODUCTION

For the purposes of the Power Plan, resource adequacy is defined as:

> *A condition in which the Region is assured that, in aggregate, utilities or other load serving entities (LSE) have acquired sufficient resources to satisfy forecasted future loads reliably.*

This definition is not intended to include problems such as localized failures in the distribution system or outages caused by operational problems or system element failures in the interconnected transmission system. It is intended to protect against power failures resulting from not having adequate generating capacity deliverable to load or the inability to fuel generators under extreme conditions. Here in the Northwest, the primary concern has been whether there are sufficient non-hydro resources available to meet loads when the "fuel" for hydroelectric generation is limited under historically low or "critical" water conditions.

As was discussed in Chapter 1, The Western Electricity Crisis of 2001-2002 is widely believed to have had its roots in resource inadequacy. For a number of reasons, resource development in the 1990s failed to keep pace with growth in the region and, in fact, the entire West. When poor hydro conditions manifested themselves in the summer of 2000 and on into 2001, the underlying tight supply was made apparent and wholesale prices went out of control. The lights never went out in the Northwest during 2000 and 2001 but the region experienced extremely high wholesale prices. This occurred even though large amounts of load, mostly from the Direct Service Industries, were taken off the system. Consumers' reactions to these extreme prices suggest the possibility of a different adequacy concept – that of an "economic" resource adequacy. Planning to maintain "economic" adequacy likely means building more and possibly different types of resources.

ANALYSIS

To begin to inform the discussion of an adequacy standard, the Council has undertaken two complementary analyses. One addresses physical adequacy – the ability to meet load. The other addresses economic adequacy – the avoidance of extremely high costs that can result from tight supply conditions. The first analysis uses the GENESYS model, which performs a detailed simulation of the Northwest power system, to assess the ability of the system to meet load with variations in hydro conditions, temperatures and generator outages. The second analysis uses the portfolio model, described in Chapter 6, to explore the cost/risk tradeoff over a large number of possible futures.

GENESYS Analysis

The GENESYS model was developed in 1999 to assess the adequacy of the regional power supply.[1] One of its most important features is that it is a probabilistic model, that is, it incorporates future uncertainties into its analysis. Each GENESYS study involves hundreds of

[1] *Northwest Power Supply Adequacy/Reliability Study Phase 1 Report*, Council Document 2000-4, March, 2000. http://www.nwcouncil.org/library/2000/2000-4.pdf

simulations of the operation of the power system. Each simulation is performed using different values for uncertain future variables, such as precipitation (which affects the amount of water for hydroelectric generation) and temperature (which affects the demand for electricity).

More precisely, the random (or uncertain) variables modeled in GENESYS are Pacific Northwest stream flows, Pacific Northwest demand and generating-unit forced outages. The variation in stream flow is captured through incorporation of the 50-year (1929–1978) Pacific Northwest streamflow record. Uncertainty in demand is captured through use of a weather (temperature)-driven demand model. The demand algorithm in GENESYS uses daily average temperatures to forecast hourly demands. In order to maintain the correlation between temperature and precipitation (river flows), the model is normally run with these two variables in lockstep, meaning that the corresponding historical temperatures are used for each selection of historical water condition.

GENESYS does not model long-term demand uncertainty (not related to temperature variations in demand) nor does it incorporate any mechanism to add new resources should demands grow more rapidly than expected. It performs its calculations for a known system configuration and a known demand forecast, which can change over time. In order to assess the physical adequacy of the system over different long-term demand scenarios, the model must be rerun using the new demands and the corresponding new resource additions. The portfolio model (described below) deals with long-term demand uncertainty explicitly as well as other long-term uncertainties. .

Another important feature of GENESYS is that it captures the effects of "hydro flexibility," that is, the ability to draft reservoirs below normal drafting limits in times of emergency. Hydro flexibility can be particularly important in helping address potential supply problems during extended periods of high demand associated with extreme cold events. In order for GENESYS to properly assess the use of this emergency generation, a very detailed hydroelectric-operation simulation algorithm was incorporated into the model. This logic simulates the operation of individual hydroelectric projects over 14 periods of the year (April and August are split because they are the transition months between fall-winter and spring-summer). The portfolio model has a much more simplistic representation of the hydroelectric system.

The probabilistic assessment of adequacy in GENESYS provides much more useful information to decision makers than a simple deterministic (static) counting of resources and demands. Besides the expected values for hydroelectric generation and dispatched hours for thermal resources, the model also provides the distribution (or range) of operations for each resource. It also identifies situations when the power supply is not able to meet all of its obligations. These situations are informative because they identify the conditions under which the power supply is inadequate. The frequency, duration and magnitude of these curtailment events are recorded so that the overall probability of not being able to fully serve loads is calculated for the power system being studied. This probability, commonly referred to as the loss of load probability (LOLP), is the figure of merit provided by GENESYS.

It should be noted that in determining the LOLP, an assumption is made in GENESYS that all available resources will be dispatched in economic order to "keep the lights on", no matter what the cost. As such, the LOLP is a physical metric, not an economic one.

Having a model to assess the LOLP for a given configuration of the power supply is very useful but planning for future expansion cannot occur until a standard is defined. In other words, what value of LOLP defines an adequate system? While many regions in the United States use some

form of a probabilistic method to calculate a loss-of-load type of metric, no well-defined standard exists. In fact, there is a great variation in the definition of loss-of-load metrics. For example, some regions calculate a metric using resource forced outage as the only uncertain variable.

For the Northwest, we have defined an adequate system to have an LOLP no greater than 5 percent over the winter period. This means that of all the simulations run, with uncertain water conditions, temperatures and forced outages, no more than 5 percent had winters when not all demands could be met. Such a system faces a maximum 5 percent likelihood that some winter demands will not be served due to inadequacies in the generation system (not counting potential problems in the transmission network).

But what constitutes a curtailment event? Since the GENESYS model cannot possibly simulate all potentially varying parameters nor can it know precisely every single resource that is available, a threshold is used to screen out inconsequential events. Our standard is based on a threshold of 1,200 megawatt-days. This corresponds to the loss of power to a city about the size of Seattle, Washington for a period of 24 hours. It represents 28,800 megawatt-hours of curtailment. In our assessment of the LOLP for the northwest, each simulation performed that shows a total curtailment of 28,800 megawatt-hours or more over the winter period is counted as a curtailment event. More precisely then, a 5 percent LOLP means that there is a 5 percent likelihood that over a winter period 28,800 megawatt-hours of service or more will be curtailed.

The Northwest is not an island

In the past, the Northwest planned (at least in theory) to a critical-water standard, i.e., that there should be sufficient Northwest resources, including the hydroelectric generation produced given the driest historical water condition, to just meet forecasted loads. This standard originated when the Northwest was essentially isolated from the rest of the Western system by limited transmission links and was continued when high oil and gas prices dominated generation markets in the rest of the West. However, since the interties were constructed, and more recently, oil and gas prices collapsed in the mid-1980s, the region has not necessarily needed to balance in-region resources and demand under critical water conditions in order to maintain a physically adequate power supply. The reasons for this are twofold; 1) in almost all years, hydroelectric generation will exceed that produced under critical water conditions and 2) the Northwest is connected electrically to the southwest, which almost always has surplus winter energy to export (the southwest is a summer peaking region and the northwest is a winter peaking region).

In the past, reservoirs were operated in the fall and early winter under the assumption that the region would realize better than critical water conditions. Should a dry year ensue, the region could import surplus energy from the southwest. There was also the contractual ability to interrupt a portion of the Direct Service Industry load when out-of-region surplus energy was not available. These contractual agreements with the DSIs no longer exist. But, the Northwest is still connected to the southwest. Both regions should be able to benefit from the diversity in peak demand seasons. Consequently, determination of adequacy should reflect the ability to import power from outside the region. However, the implication of this is that any Northwest adequacy standard and determination must be closely coordinated with other entities in the Western Interconnection.

GENESYS models inter-regional transactions among the northwest, Canadian and southwest regions. Northwest contractual export obligations are served as though they were regional demands. During emergencies, when surplus out-of-region capacity is available, it can be dispatched to counter schedule existing exports and, if necessary, to import additional generation into the northwest.

How much should we rely on imports?

A difficult planning question is how much out-of-region surplus capacity should we rely on? Clearly, assuming that no surplus out-of-region capacity is available is too conservative and possibly too costly. Assuming the maximum amount of available out-of-region surplus may be too risky. Some level in between, calculated with the tradeoff between risk and cost in mind, would be more appropriate for planning purposes. Currently the region is over 1,000 average megawatts surplus relative to critical water generation, assuming that generation from northwest merchant resources not associated with load serving entities would be available to serve regional demand. Because of the surplus, the current estimate for LOLP is under one percent, which means that the region does not have to depend on out-of-region imports to maintain an adequate supply. However, it is important to know how the adequacy of the northwest power supply changes as the surplus goes away. At what point does the region need to take action to maintain an adequate supply?

Figure 8-1 below illustrates the relationship between the LOLP and available out-of-region surplus capacity, for different levels of load/resource balance. Generally speaking, the more surplus that is available from out of region, the lower the LOLP will be. For example, consider the case where the region is 2,000 average megawatts deficit on a firm basis (the curve with the diamond-shaped points in Figure 8-1). Assuming that a 5 percent LOLP represents an adequate power supply, then the northwest would be adequate (even though the load/resource balance is negative) if at least 4,000 megawatts of surplus winter capacity were available from out-of-region utilities. If no out-of-region surplus were available, the projected LOLP would be on the order of 25 percent -- well over the standard. Even if the northwest were in load/resource balance (the far left curve with the circular points), the LOLP would be over 5 percent with no available out-of-region imports. So, the region should incorporate some level of available out-of-region generation in its planning process. The question is how much?

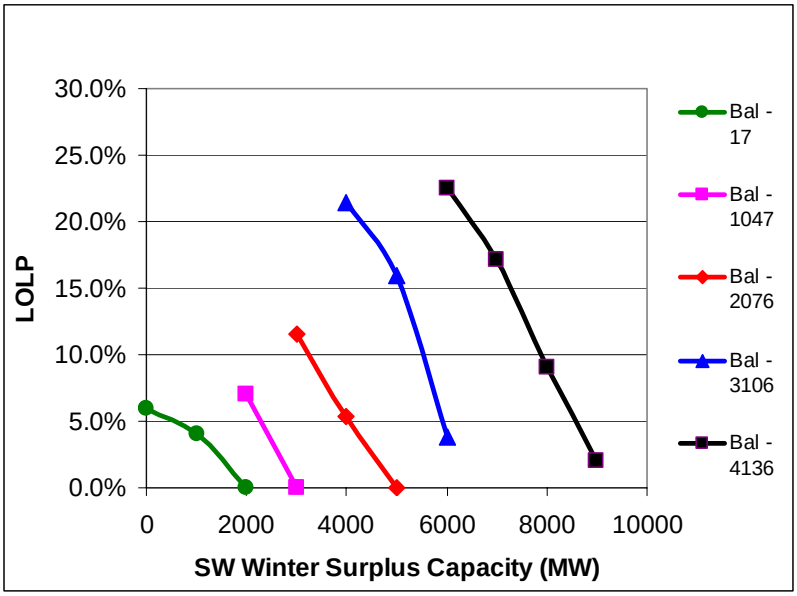

Figure 8-1: LOLP as a Function of Available SW Capacity (For Different Load/Resource Balance Conditions)

To make the relationship between LOLP and out-of-region surplus a little easier to see, the values in Figure 8-1 for all the points that cross the 5 percent LOLP level are plotted in Figure 8-2. In that figure, every point on the plotted curve has the same reliability, namely a 5 percent LOLP. Given a particular load/resource balance in the northwest (horizontal axis), this graph shows how much out-of-region surplus capacity (vertical axis) is required to maintain an adequate system. Again, using the same example as above, if the region were deficit by 2,000 average megawatts, it would require about 4,000 megawatts of surplus winter capacity in order for the northwest to maintain a 5 percent LOLP. This does not mean that the region would import 4,000 megawatts over the entire winter. In fact, the average amount of imported energy for this case is about half of that but in some hours the full 4,000 megawatts would be imported.

The question of how much out-of-region surplus the northwest should rely on for planning purposes, however, remains unanswered. If California goes forward with aggressive adequacy standards, it should mean that California should have ample surplus for years to come. However, current and potentially new air-quality concerns may limit the operation of surplus resources in California. In addition, future proposals to add a carbon tax to the operation of fossil-fuel burning resources may diminish their availability to the northwest. For the time being, with a surplus northwest, this issue is not urgent but at some point in the near future the region must assess what level of inter-regional dependence it wishes to rely on to plan future power system expansion.

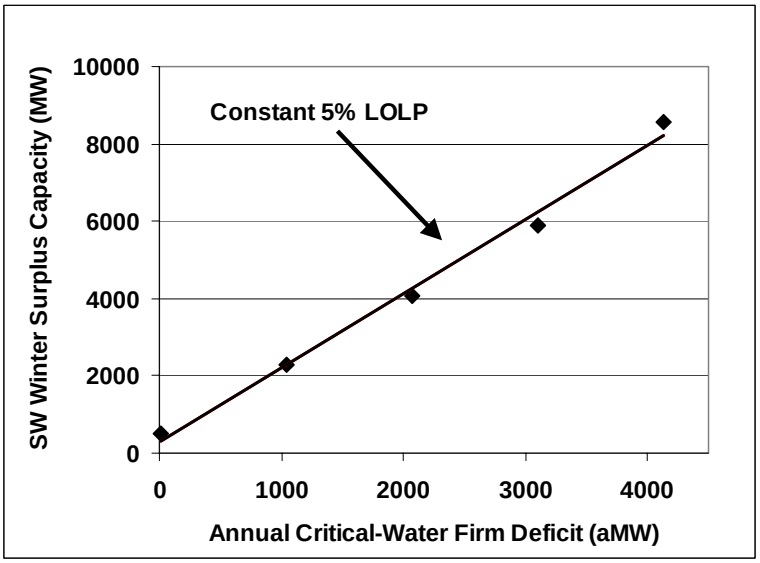

Figure 8-2: Relationship between SW Surplus Capacity and L/R Balance

As an alternative to using the relationship between available SW surplus capacity and NW load/resource balance for resource planning purposes, the relationship between SW surplus capacity and NW hydro conditions may be even more useful. Figure 8-3 below illustrates that relationship. As in Figure 8-2, each point on this graph reflects the same resource adequacy, namely a 5 percent LOLP. The curve in Figure 8-3 tells us that if no SW surplus winter capacity is available (lower right corner) then the northwest should plan to the 100 percent adverse hydro condition (or what has historically been called critical water) to assure a 5 percent LOLP. Alternatively, if 4,000 megawatts of SW surplus capacity were available, the northwest would plan its resource development based on the 78th percentile water condition to assure the same level of reliability. This is equivalent to planning to a 2,000 average megawatt firm deficit load/resource balance (as described for Figure 8-2). This alternative method, used to guide resource development in the northwest, may be more easily incorporated into individual utility's resource planning processes. Adopting such a method for northwest resource planning should have the effect of lowering costs while not sacrificing reliability (relative to planning strictly on critical water). However, the key parameter remains to be the amount of available SW surplus winter capacity that the northwest wishes to rely on.

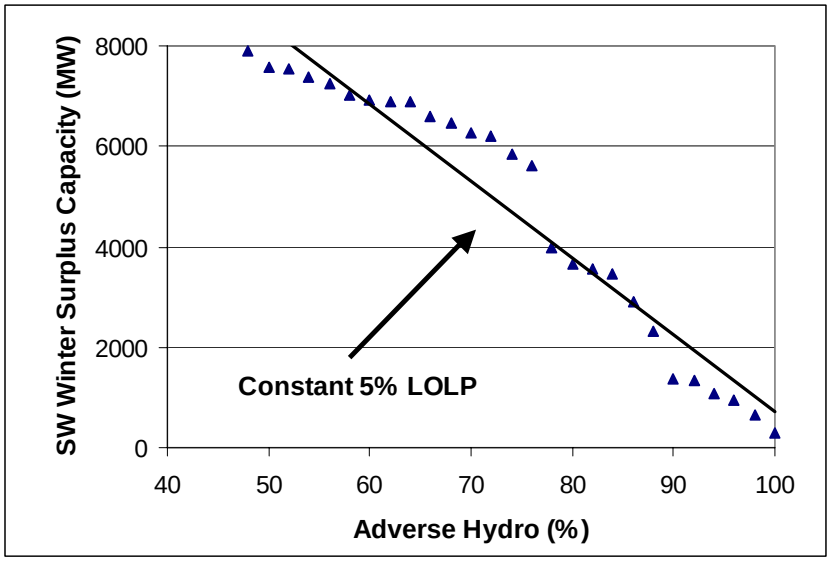

Figure 8-3: Relationship between SW Surplus Capacity and Adverse Hydro

Portfolio Analysis

As described in Chapter 6, the portfolio model tests different regional resource plans, calculating the expected cost and risk associated with those plans over a large number of possible "futures". Those plans consist of the types, quantities and schedules for new resource development. The futures involve different patterns of load growth, hydro conditions, fuel prices and electricity market prices over the planning period. While the model calculates physical loads and resources, it makes its choices purely on economics. Does this plan lower the average net present value system cost? What is the risk? Is there a plan that lowers the risk? What is the cost? For a given level of risk, the model searches for the mix of resource types, amounts and schedule for resource development that yields the minimum expected cost over a wide range of possible futures.

In the portfolio model, the region is exposed to the market price of electricity. That market is essentially the West Coast. If there are excess Northwest resources whose variable costs are less than the market price, they can be sold into that market up to the export capability of the transmission system. Conversely, if there are insufficient Northwest resources to meet load, the region can purchase from that market up to the import capabilities of the transmission system. The average market price over all the futures corresponds to the electricity market price forecast described in Chapter 2. However, for any given future, the market price can look much different. The market price is affected by a number of factors such as natural gas prices and hydro production. And, it also reflects other factors such as possible extended forced outages of major resources outside the region, new technologies, extreme weather and even the "psychology" of the market. In addition, market prices must 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 will be reduced until generation equals loads plus export capability. Similarly, if generation is inadequate to meet requirements, given the region's import capability, prices will increase until the situation is resolved, e.g., loads are reduced or the price induces sufficient

generation. The tradeoff evaluated in the portfolio model is between the risk of exposure to high market prices against the fixed costs of the additional resources to protect against that exposure.

The conventional wisdom has been that we are better off to risk some exposure to the market than to incur additional fixed costs for resources that may run relatively infrequently. That was clearly so when the market was well behaved and the resource choices tended to be highly capital intensive, had long construction lead times and were exposed to high interest rates. The Council's earlier plans devoted a great deal of attention to managing this fixed cost risk.

The current analysis suggests that this view should perhaps shift. Certainly the characteristics of most of the resources have changed in such a way as to reduce fixed cost risk – smaller unit sizes, shorter lead times, lower capital costs. In addition, interest rates are much lower than those assumed in earlier plans. However, recent experience would also lead us to believe the market may be less well behaved than it was in the past and that there is little tolerance among the public and policy-makers for price volatility. While people are aware of many of the issues that brought about the 2000-2001 electricity crisis, certainly not all them have been resolved. In characterizing the uncertainty about electricity market prices, the analysis did not include periods as severe as 2000-2001 and maintained the current $250 per megawatt hour price cap. But it did include a number of futures with significant market price excursions.

Although not entirely comparable, the results of the portfolio analysis suggest maintaining a higher level of in-region resources than indicated in the GENESYS analysis. The role these additional resources play is to reduce the necessity of high priced market purchases. At the same time, however, the analysis also indicates that if the overall level of regional resources and access to those resources is sufficient, overbuilding is a more expensive and more risky alternative than some level of reliance on the market.[2] The challenge is to find the right balance.

ADEQUACY "STANDARDS"

Most of the discussion in the region and the rest of the West has been directed toward the development some sort of adequacy standard that would apply to load serving entities (LSEs). The Federal Energy Regulatory Commission (FERC) proposed an adequacy standard as part of its Standard Market Design. However, that standard was inappropriate for an energy-constrained, hydro-dominated system like that in the Northwest. FERC has subsequently deferred to the states but in the absence of state or regional action, it might attempt to reassert authority in this area. In addition, the North American Electrical Reliability Council (NERC) has begun the process of developing a power supply adequacy standard.

The NERC Resource and Transmission Adequacy Task Force of the Planning Committee recently released a report that contains recommendations for both resource and transmission adequacy. The report was adopted by the NERC Board at their June 15th , 2004 meeting. NERC is planning to follow through with the Board-adopted recommendations of its Resource and Transmission Adequacy Task Force by charging the Resources Issues Subcommittee to draft a standard authorization request (SAR) for resource adequacy incorporating the task force's recommendations. Associated with this new standard will be provisions for a compliance review process to ensure that the regional reliability councils, such as WECC, are establishing resource

[2] Regional resources are those resources located in the region and not contractually committed to extra-regional customers as well as extra-regional resources that are committed to regional loads.

adequacy processes. Although it is not clear how accountability to WECC for compliance with this standard will be determined, some level of accountability by sub-regional entities, such as the Northwest Power Pool or by individual LSEs, is likely. The latter are the only ones in a position to comply with such a resource adequacy requirement. While compliance is not ultimately legally enforceable, the standards would most likely be adopted and implemented anyway, as are current NERC and WECC standards. A possible approach to accountability might be similar to the approach taken to ensure transmission reliability whereby utilities have voluntarily entered into agreements with one another to abide by certain standards, even including provisions for sanctions if violations occur.[3]

In response to potential NERC action and work done by a group from the Committee on Regional Electric Power Cooperation (CREPC), of which the Council is a member, WECC is evaluating proposing a power supply adequacy standard, although the details have not been fleshed out. The Council has been working with others in the region to address the question of power supply adequacy for the Northwest. The Council convened the Adequacy Forum and has been working with CREPC and its Western Resource Assessment Team (WRAT). The hierarchy of options for increasing the assurance of resource adequacy that have been identified are:

- Improving the availability and transparency of relevant information;
- Enhancing the assessment of adequacy through consistent metrics;
- Establishing voluntary adequacy targets; and
- Establishing enforceable standards.

In the current absence of a standard, a focus has been placed on improving information about the status of resource adequacy. The Northwest Power Pool is working to improve the consistency of information reported by control areas in the region so that meaningful assessments can be performed. Supported by the WRAT, WECC is currently enhancing the scope and utility of its twice-yearly resource assessments. Improvements may include using probabilistic methods to assess both peak hour and longer-term energy supply inadequacies. The aim is to provide a better description of the Western energy power supply situation as context for decisions by LSEs, commissions and developers. WECC has also established an ad hoc Resource Adequacy Workgroup under its Reliability Subcommittee to propose resource adequacy criteria by which to assess the adequacy of the Western Interconnection (WI) and sub-areas within the WI.

Some states, through their public utility commissions (PUCs), do have the ability to implement adequacy standards for the utilities they regulate. The California PUC recently adopted an adequacy standard. The order requires that the investor-owned utilities it regulates have a 15-17 percent reserve margin over their peak loads, with the requirement being phased in by no later than January 1, 2008. This 15 percent planning reserve includes the approximately seven percent operating reserves required by WECC. The order also requires that LSEs forward contract for coverage of 90 percent of their summer (May through September) requirements, which consist of

3 The reliability title of the proposed National Energy Bill prohibits the NERC successor organization and FERC from requiring resource construction as part of implementing the reliability responsibility under the bill, which would make reliability standards legally binding. Currently, standards are ultimately voluntary, but almost universally followed by the industry.

their peak load plus the 15 percent reserve, one year in advance. This requirement will be phased in during 2007 (no month specified). Some believe this standard goes beyond that which would be required to assure adequacy in a purely physical sense and is intended to limit California's exposure to the risk of extreme prices.

An Adequacy Standard for The Northwest

While activities at the NERC and WECC levels could lead to enforceable standards, the outcome is uncertain. The Council believes that other regional actions can and should be pursued. This is made more critical by the possibility of changes in the role of the Bonneville Power Administration (Chapter 11) that could result in more responsibility for the assurance of adequacy being placed on entities that have not heretofore directly had that responsibility. While some may desire an enforceable adequacy standard, there are currently no institutions in the Northwest that could enforce such a standard for the Region's entire load serving entities.

Given the institutional problems associated with an enforceable resource adequacy standard, it may be possible to build on the Northwest's tradition of regional cooperation and establish a voluntary resource adequacy standard. Such a standard would need to be supported by voluntary reporting of load, resource and power system data by regional load serving entities and could be as successful as an enforceable standard. One avenue for implementing such a voluntary standard may be through the WECC voluntary contractual approach. However, if such a voluntary approach falters, an enforceable resource adequacy framework may need to be established that draws upon existing jurisdictional authority, currently available contractual mechanisms and possibly even new legislation.

In addition, it is also clear that establishing a regional adequacy standard that is incompatible with actions in the rest of the West could be less than effective. It will therefore be necessary to continue to work in the context of the WECC and other west-wide organizations.

Physical Adequacy, Economic Adequacy or Both?

In establishing an adequacy standard, it will be essential that the purpose of that standard be well understood and agreed upon. For example, is the purpose of an adequacy standard to ensure that the "lights stay on" with an acceptably high probability or is it to protect against the economic and social costs that can accompany periods of short supply? As noted earlier, the Council's analysis indicates that the latter implies a somewhat greater level of resources than the former.

Different adequacy standards could be appropriately applied at different levels. For instance, a physical standard might be most appropriately applied at the WECC level. At this level it would act to set a baseline for expectations about physical reliability of the system and for actions by LSEs and their regulators to address those expectations. Considerations of economic adequacy might better be addressed at the individual LSE (or perhaps state policy) level, where different degrees of risk tolerance might exist and different mechanisms for mitigating price risk could be put in place.

The Council believes that the question of economic versus physical adequacy should be addressed as part of the dialog surrounding the establishment of a Western and Northwestern adequacy standard. Toward this end, the Council will establish a Northwest Resource Adequacy Forum. This forum will examine alternative adequacy metrics and standards for the Northwest and their consistency with west-wide standards being developed by the WECC and others. The

forum should consist of utility policy makers, regulatory commission representatives and other relevant parties who will help to develop standards and support their implementation. A technical subgroup of this forum will have the function of providing policy makers viable options for both metrics and standards for the northwest. The objective would be to reach agreement on appropriate adequacy metrics and standards by the end of 2005. The Council will continue to work within the WECC and other groups toward the establishment of adequacy metrics and standards on a west-wide basis.

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;

[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

- 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;

- 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.

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[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

Recently, the Regional Representatives Group (RRG) of Grid West has taken some promising steps toward a resolution. The RRG, composed of representatives of interest groups in the region, including Bonneville, other utilities, and regulators, has worked collaboratively to identify a structured, incremental approach to reforming the management and operation of the transmission system. The proposal identifies a desirable target state that could address the key identified problem areas, 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 reliable operation of the regional power system. 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 efficient, low-cost transmission system operation and 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 and their costs can be a major barrier to acquisition of needed and cost-effective resources. A preliminary analysis was carried out of the cost and lead times associated with joint development of a 1000 megawatt coal plant in eastern Montana and the transmission required to bring that power into the Northwest grid at the Mid-Columbia trading hub. This analysis indicated that the lead times were comparable (about 84 months) and that the cost of the transmission was somewhat more than half the total cost. A similar analysis for 1000 megawatts (capacity) of wind development in eastern Montana found that the lead-time for the transmission was the pacing item (84 months for the transmission compared to 38 months for complete build out of the wind development). Again, more than half the capital costs were associated with the transmission.

Efforts are under way, both westwide and in the Pacific Northwest, to assess 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 has developed its study program and begun some initial focused studies. Included is a study of the transmission requirements to access Montana resources. The results of this study will provide a more refined assessment of costs and lead times than that discussed in the preceding paragraph.

Bonneville convened a large group of stakeholders beginning in January 2003 to consider how to identify and implement "non-wires" 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

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

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.
- 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 Grid West RRG process appears so far to have largely moved beyond regional conflicts over transmission reform. It needs to continue making progress, on a steady pace and through a collaborative process, in resolving the more serious problems affecting the transmission system as quickly as possible. 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.

However, should the Grid West effort founder, the region will need to find some other comprehensive mechanism or mechanisms to address these problems. There are a number of decision points coming up in the next year in the RRG/Grid West process. If the Grid West process appears unlikely to be able to reach successful conclusion by the end of 2005, the Council is committed to seeking alternative solutions to the issues facing the region's transmission system. Many of the problems are larger in scope than a single transmission owner or control area and solutions are unlikely to be found by focusing on any single owner.

Power Planning and Fish and Wildlife Program Development

RELATIONSHIP OF THE POWER PLAN TO THE FISH AND WILDLIFE PROGRAM: SUFFICIENT RESOURCES TO MEET ELECTRICITY DEMANDS AND THE REQUIREMENTS FOR FISH AND WILDLIFE

The Power Act requires that the Council's power plan and Bonneville's resource acquisition program assure that the region has sufficient generating resources on hand to serve energy demand and to accommodate system operations to benefit fish and wildlife. The central purpose of this chapter of the power plan is to explain how the Fifth Power Plan satisfies this statutory responsibility. This chapter also includes recommendations for how to improve the way in which power issues are considered in fish and wildlife decisionmaking and vice versa.

The Act requires the Council to update its fish and wildlife program before revising the power plan, and the amended fish and wildlife program is to become part of the power plan. The plan is then to set forth "a general scheme for implementing conservation measures and developing resources" with "due consideration" for, among other things, "protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival and propagation of anadromous fish." Northwest Power Act, Secs. 4(e)(2), (3)(F), 4(h)(2).

Bonneville in turn is to acquire sufficient generating resources, consistent with the Council's power plan to (1) meet its contractual obligations for power supply and (2) "assist in meeting the requirements of section 4(h) of the program" – that is, the requirements of the fish and wildlife provisions and program. The ultimate goal, as expressed best in Section 4(h)(5) concerning the fish and wildlife program, is to assure the region an "adequate, efficient, economical and reliable" power supply while at the same time allowing for the operations and other program elements that will "protect, mitigate and enhance" fish and wildlife populations. (Northwest Power Act, Secs. 2(6), 4(h)(5), 6(a)(2))

Whether Bonneville had sufficient resources to meet these needs became a big issue when the drought year of 2001 coincided with the fact that Bonneville had contracted for firmer loads than it had resources to serve and the wholesale power market could not supply the difference at a reasonable price. Just at the time the Council initiated the process of amending the mainstem portion of its fish and wildlife program, it appeared that neither the region nor Bonneville had the resources to meet either need, let alone both. In other words, the region did not have the resources (under such a low water year) to both serve regional loads and provide adequate operations for fish. As a result, the Council received a number of recommendations during the mainstem amendment process regarding power supply, resource development, and power planning.

By the time the Council finished the mainstem amendments in 2003, things had changed, at least for the near term. The region had lost over 2000 average megawatts of demand and gained over 3,000 average megawatts of new resources. Because of this, the region went from about a 4,000 average megawatt deficit (using a critical water standard) in 2000 to over a 1,000 average megawatt surplus in 2004. Bonneville's particular situation changed accordingly. Thus the Council's official assessment, as part of its mainstem amendment findings about assuring the

region an "adequate, efficient, economical and reliable power supply" (known as the AEERPS finding), was that in the short term, the region and Bonneville had sufficient resources to meet, without undue threat, both the electricity loads that remained and fish and wildlife operations. But, the Council promised that it would take a long-term look at this situation as one of the key issues in the power plan.

The Fifth Power Plan addresses these issues in this way: analyses of future demand and existing resource availability, taking into consideration both physical and economic risk, indicate that the region and Bonneville presently have enough generating resources to meet power supply needs for some time to come. With recommended actions to pursue cost-effective conservation, the region should be able to stave off the cost of new resources or the risk to power supply for much longer. The Council also recommends that Bonneville not contract to deliver more power than the existing system is able to generate under critical water conditions, except in bilateral deals in which the customers bear the cost and risk of any new resources Bonneville has to acquire to serve that extra load. The Council concludes that resources should be ample to meet electricity demands and to stabilize the delivery of fish and wildlife operations.

IMPROVING THE INTEGRATION FISH AND WILDLIFE AND POWER CONSIDERATIONS

While the power plan analysis serves to address the central legal relationship between the power plan, power supply resources, and the fish and wildlife program, the Council has also been investigating particular issues that are relevant to the relationship between fish and wildlife and power system operations. These include:

- How can we better integrate power considerations into fish and wildlife decisionmaking, and vice versa?
- How can we improve our understanding of the cost impacts and cost effectiveness of specific fish and wildlife operations?
- How can we improve our standards and procedures for addressing inevitable power system emergencies in the future?

The rest of the chapter addresses these issues.

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 makers to decide how to equitably allocate this resource. 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 can have 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

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

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).

Evaluating fish and wildlife measures for cost effectiveness is central to the mainstem portion of the Fish and Wildlife Program. 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.

The analysis for this power plan assumes that all fish and wildlife operations pertaining to the hydroelectric system, as outlined in the NOAA Fisheries biological opinion and the Council's program, will be followed. However, the Council realizes that emergencies may occur in which fish and wildlife operations would be interrupted. Assuring the adequacy of resources for the power system minimizes not only the risk of electrical shortages and high prices but also minimizes the risk of emergency interruptions to fish operations.

The actions identified in this power plan are based on best available scientific data and are designed to assure an adequate, efficient, economical and reliable power supply. The Council also intends that its decisions about fish and wildlife program expenditures be made carefully and that the projects that implement that program are efficient and scientifically credible. For the region to achieve both objectives, it must coordinate planning and decision-making for both power production and fish and wildlife. Outside of the Council, however, no clear process exists for integrated long-term planning.

Recommendation -- Better Integration of Planning Efforts

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.

Benefits of Integration

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

[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.

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.

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. In this sense, physical analysis by power planners plays a very important role in the development of the fish and wildlife program.

Emergency Curtailment Strategy

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 assure 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] The situation in 2000-2001 was so severe that there was little choice but to curtail almost all operations for fish. However, had the situation been less severe the region would have been ill-prepared to determine which operations to curtail or modify and which to carry out. To avoid such a situation in the future, an emergency curtailment strategy should be established. Having cost and biological impacts for individual measures allows power planners and biologists to prepare such a strategy and have it in place prior to a power emergency.

Appendix O 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.

[3] See Chapter 1.

Ultimately, an adequate power supply must also adequately provide 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 failure to provide fish and wildlife operations with measurable benefits to fish. The Council attempted to develop such a metric but found uncertainties surrounding biological benefits of fish and wildlife operations made it difficult to determine a clear and acceptable metric. Whether a metric is developed or not, the Council has the responsibility to assure the region that its power plan will provide both an adequate power supply and that it will adequately provide operations to protect fish and wildlife.

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 are paying 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

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.

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 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.
- 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]

[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

The recommendations coming from these processes have several common elements:

- 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 existing FCRPS to those customers who are willing to pay the costs of the additional resources required.

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 initiated 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 needed 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 Council Document 2004-5, *Recommendations on the Future Role of the Bonneville Power Administration in Regional Power Supply*. 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 has undertaken 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 could 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 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.

[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.

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.

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. Under a settlement, benefits could be provided in the form of power or dollars. The Council believes that providing the benefits in the form of power is more risky for Bonneville and could make the question of allocation more difficult. The Council continues to believe that however Bonneville treats the satisfaction of its exchange obligations for other accounting or financial reporting purposes, these benefits are appropriately included in the firm sales forecast called for under section 4(c)10(A) of the Act. 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 could be substantially reduced to the extent that customers can meet these objectives. But if necessary, Bonneville must be prepared to use the full extent of its authorities to ensure that the cost-effective conservation and renewables identified in the

Council's power plan is achieved on all its customers' loads.. 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.

The Act places a special emphasis on conservation. One of the fundamental premises of the Act is that by increasing the efficiency of *all* electricity consumption, from generation through transmission and distribution to its final end use, the region could extend the economic benefits of the region's low cost hydroelectric system. The Act created an ongoing responsibility for Bonneville to acquire conservation to "reduce load," not just meet load growth. And while the Council's recommendations may reduce Bonneville's responsibility for meeting load growth in the region, they would do so only for the duration of its contracts. Nothing prevents customers from bringing additional net requirements to Bonneville at the end of a contract period. For these reasons, the Council continues to support the conservation recommendations it first developed in December, 2002, as part of a public process inquiring into the future role of Bonneville, and then reconfirmed in May, 2004.[5] In summary, those recommendations were:

- The system for conservation development should: 1) rely on the Council's Plan to define the cost-effective resource; 2) rely on proven delivery mechanisms; 3) provide stabilized and adequate funding for conservation over the duration of the new contracts; 4) reinforce the role and capabilities of the Regional Technical Forum; 5) provide a mechanism for ensuring that cost-effective conservation is implemented; and 6) capture conservation at as low a cost to the power system as possible.
- Bonneville should establish conservation budgets based on Bonneville's share of regional conservation potential identified in the Council's Plan and estimated program costs to capture that conservation. However, conservation savings targets, mechanisms and policies should be designed to *encourage* conservation on all loads of preference- customer utilities, not just the part served by Bonneville.
- Bonneville's obligations and authority with respect to IOU conservation is limited to the residential and small farm loads of those utilities that are subject to the residential exchange. The Council, however, will continue to encourage and support the work of the states' utility regulatory commissions to use their authorities and least-cost planning regulations to ensure that the cost-effective conservation on all IOU load is accomplished.

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

[5] "Northwest Power Planning Council Recommendations on the Future Role of Bonneville in Power Supply," Council Document No. 2002-19 (December 17, 2002); "Recommendations on the Future Role of the Bonneville Power Administration in Regional Power Supply," Council Document No. 2004-05 (May 2004).

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 region has benefited tremendously from the last 20 years of conservation development. It has reduced loads about 2,500 average megawatts at a cost less than half of that of adding similar amounts of generation. The Council's current plan identifies significant cost-effective conservation potential that the region should pursue. This conservation is valuable to the region regardless of whether the region is developing new generation or not. Bonneville should use the full extent of its authority to ensure that all cost-effective conservation is captured in an efficient, low-cost, and timely way; and Bonneville should retain a strong and active role in the coordinated planning and implementation of conservation efforts across the region.

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 purchaser should pay the costs of providing services like storage and shaping.

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.