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.

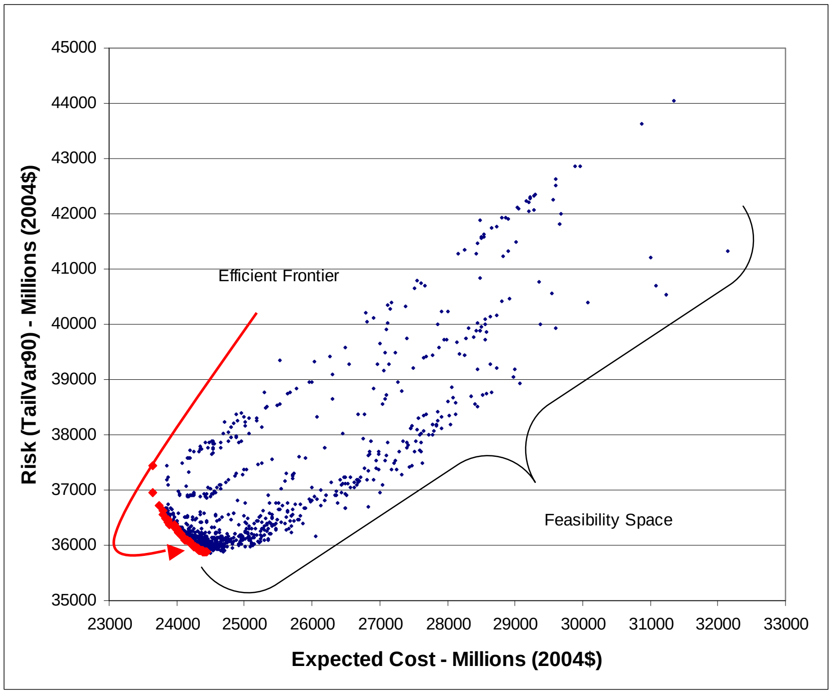

Figure 7-1: Feasibility Space and Efficient Frontier

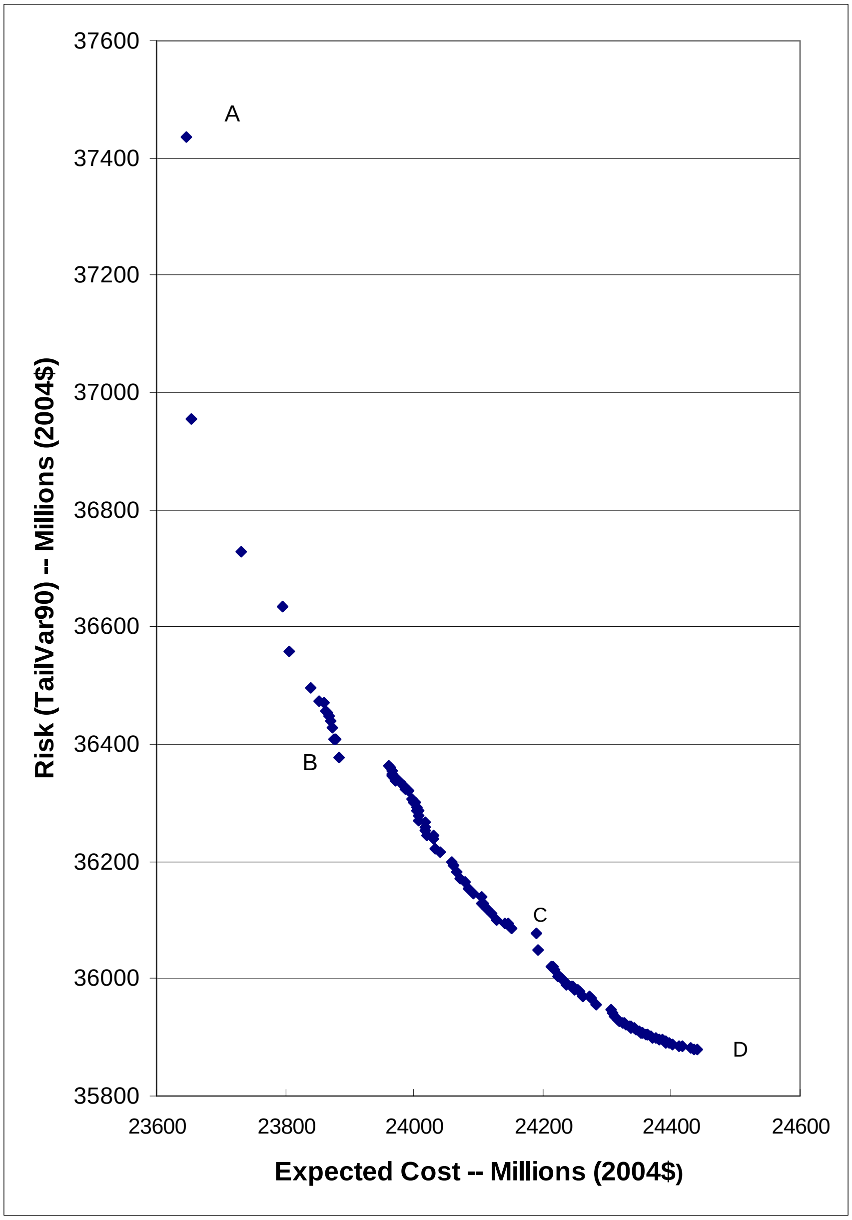

Figure 7-2: Plans Along the Efficient Frontier

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.

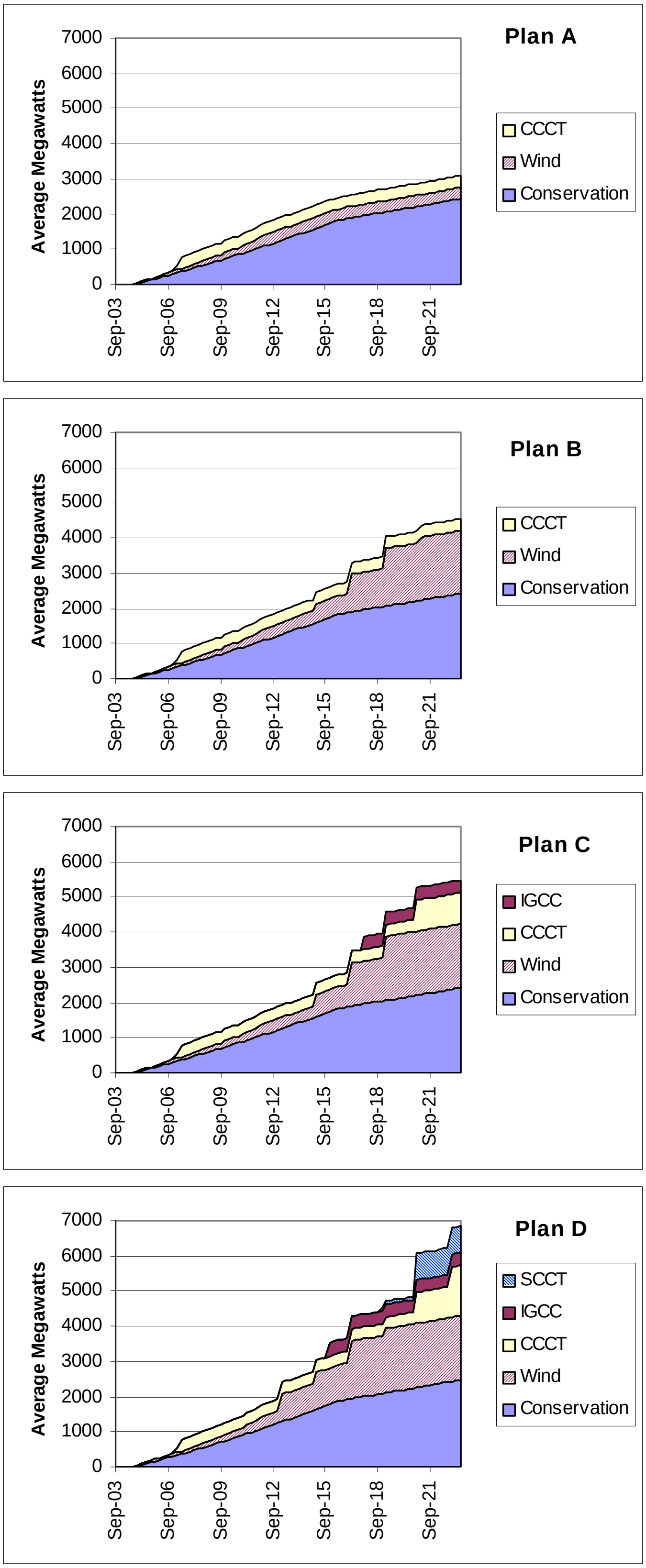

Figure 7-3: Representative Development Schedules for Altenative Plans along the Efficient Frontier

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

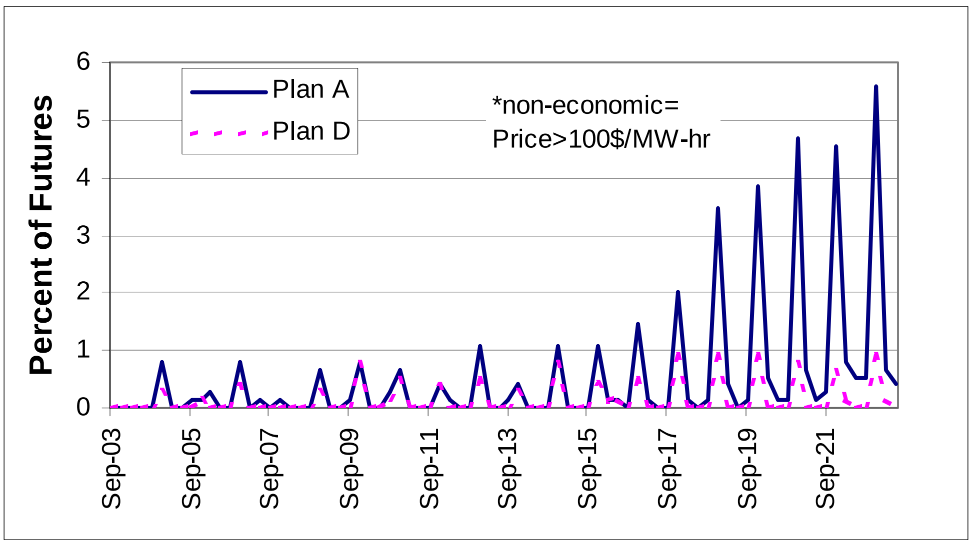

Figure 7-4: Frequency of "Non-Economic" Imports

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.

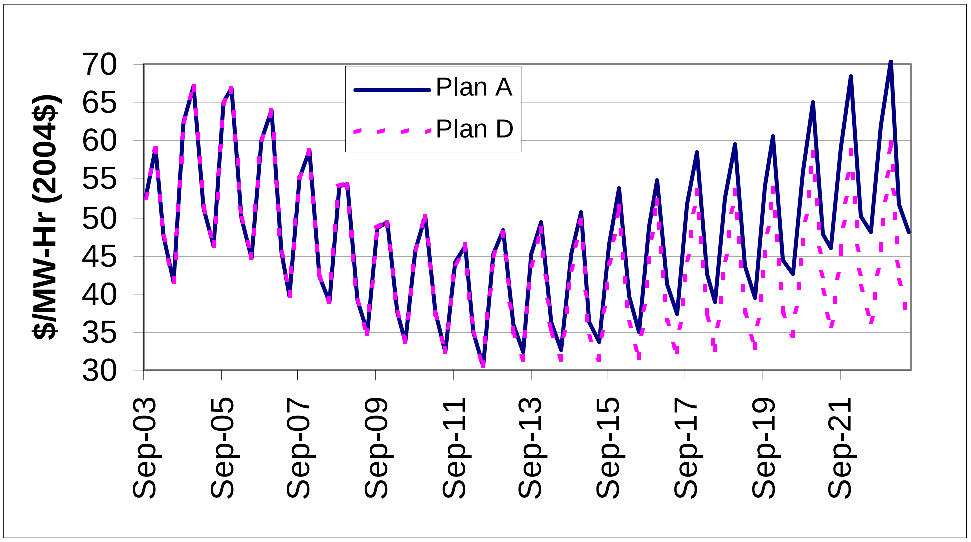

Figure 7-5: Average Quarterly On-Peak Electricity Market Prices

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.

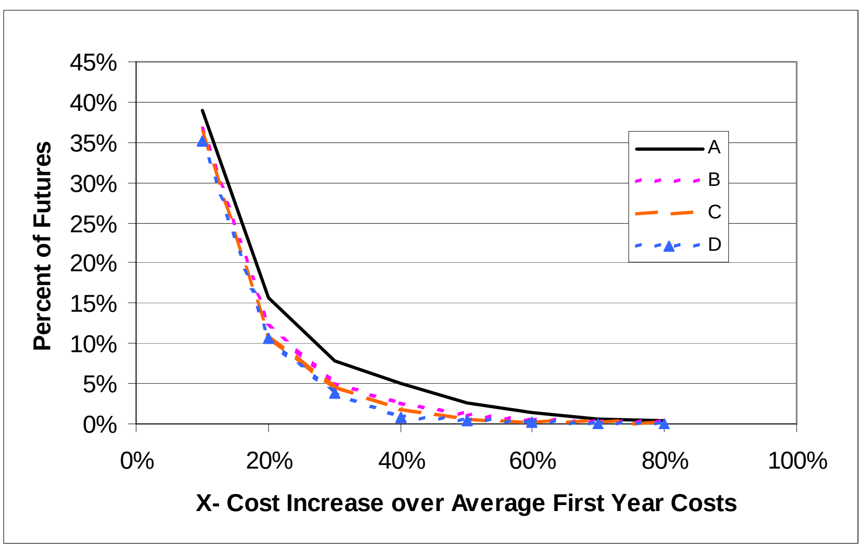

Figure 7-6: Percent Futures with Retail Cost Increases (over First Year Retail Cost) Greater than X

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

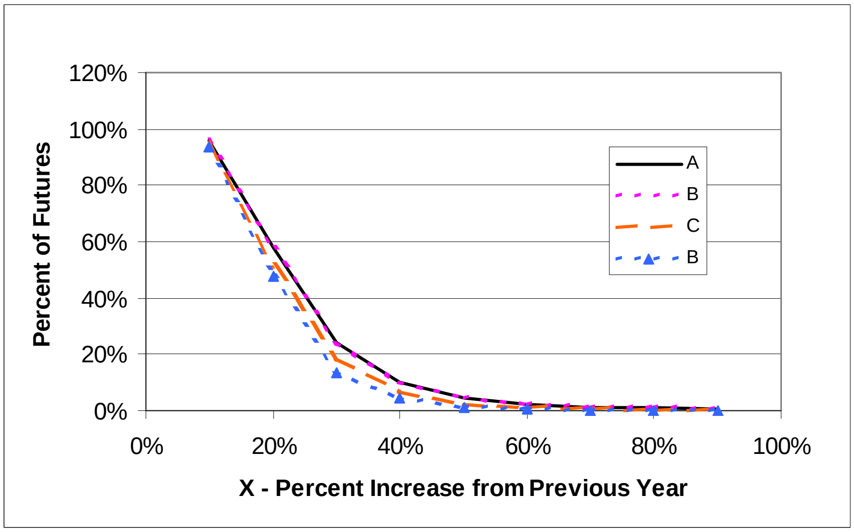

Figure 7-7: Percent Futures with Year-to-Year Cost Increases Greater than X

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.

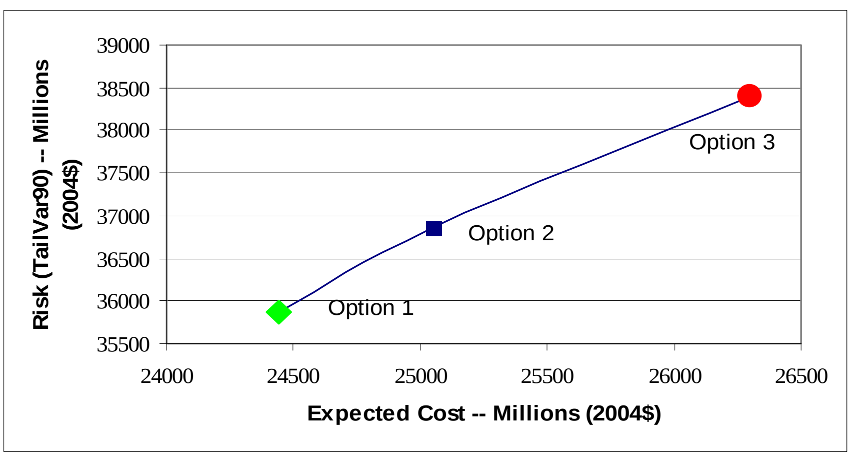

Figure 7-8: Cost and Risk of Least Risk Plans for Alternative Conservation Strategies

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 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.

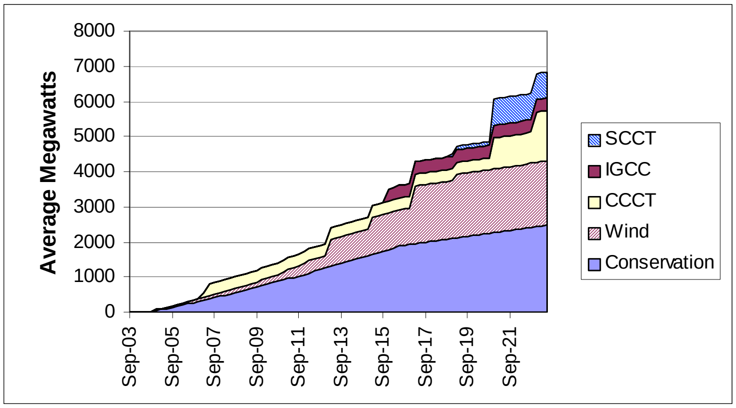

Figure 7-9: Representative Development -- Option 1: Base Case Conservation Development

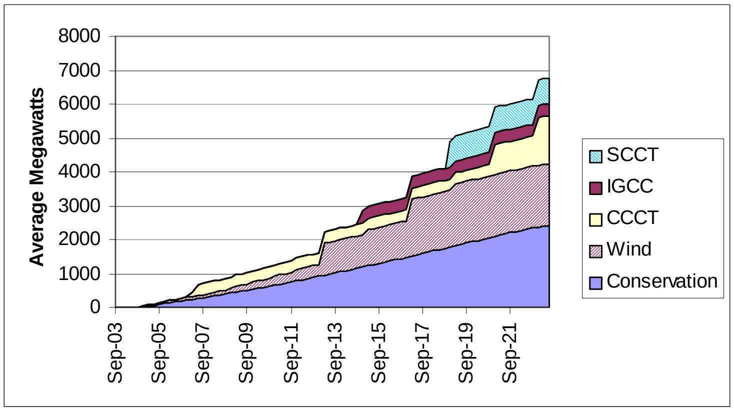

Figure 7-10: Representative Development -- Option 2:Reduced Near-Term Conservation

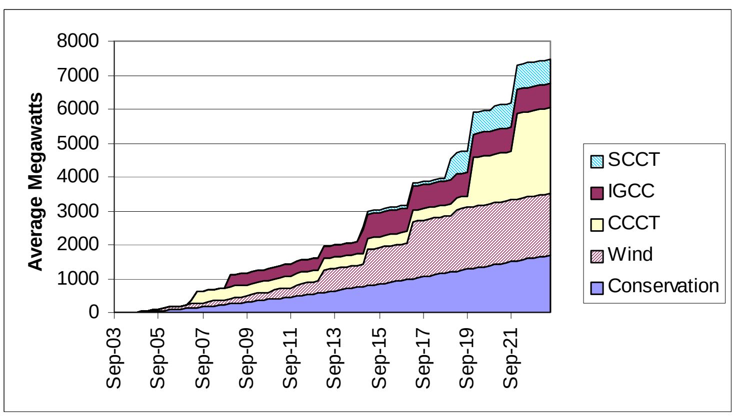

Figure 7-11: Representative Development -- Option 3: Restricted Conservation

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.

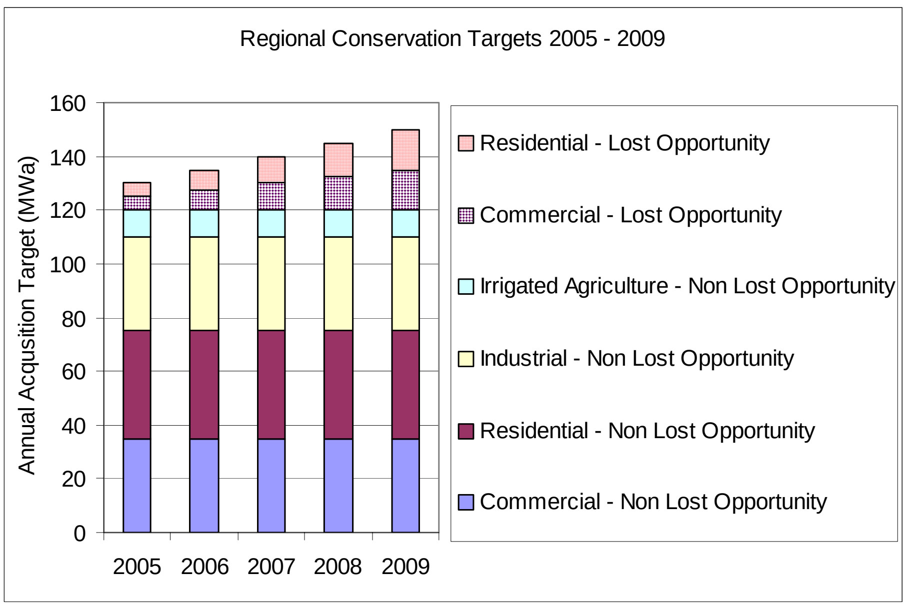

Figure 7-12

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.

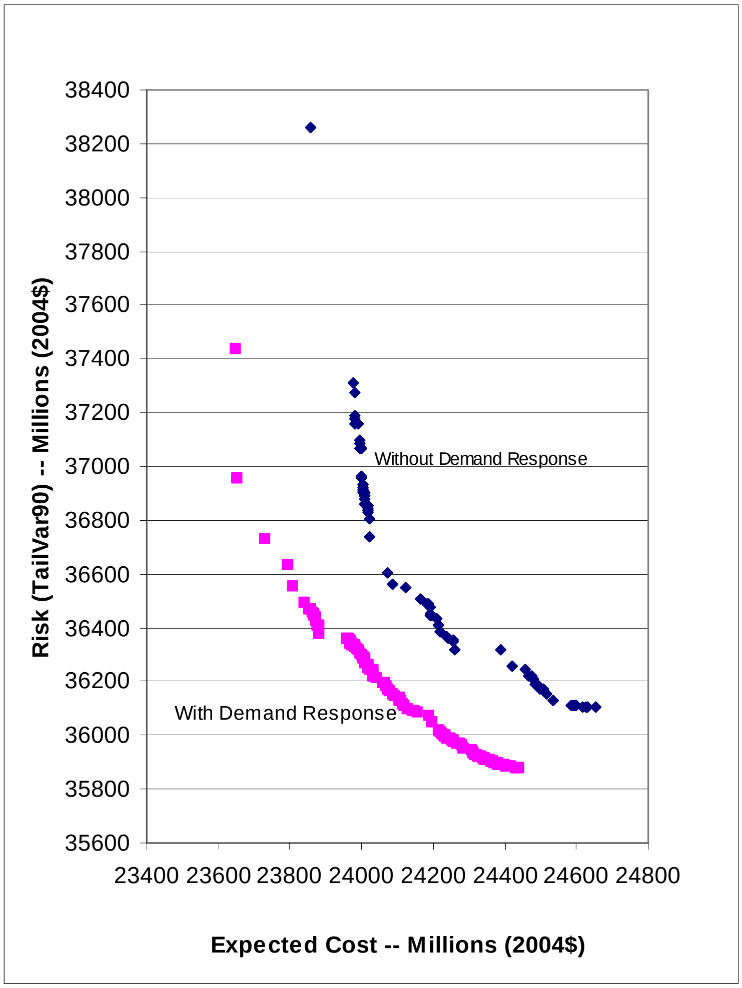

Figure 7-13: Efficient Frontiers With and Without Demand Response

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.

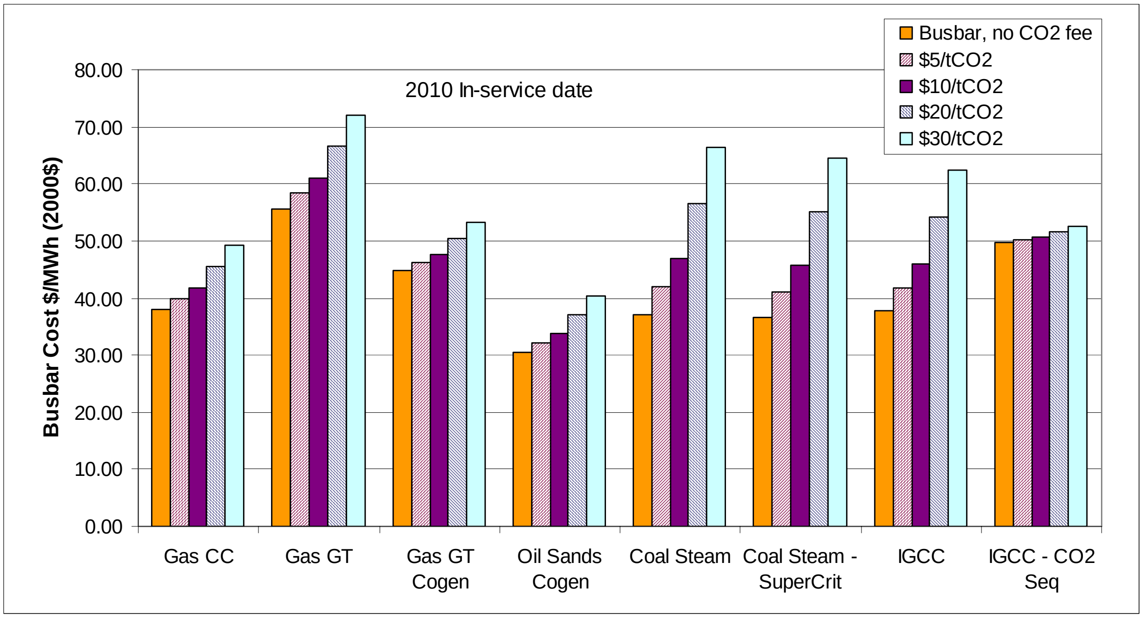

Figure 7-15: Effect of Carbon Taxes on Bus Bar Cost of Power for Alternative Generation Technologies

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

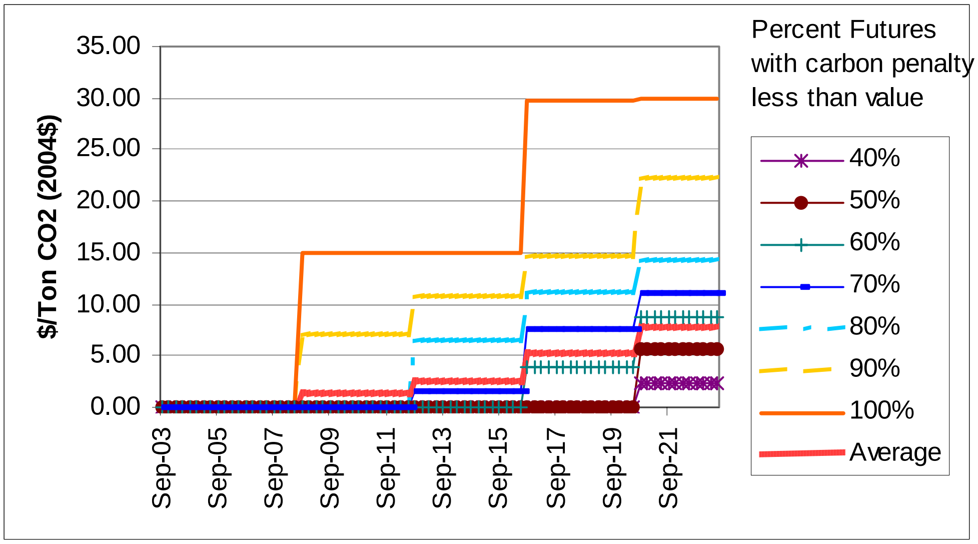

Figure 7-16: Probabilistic Representation of Future Carbon Penalty

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.

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[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 $\mathrm{TailVaR}_{90}$ 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.

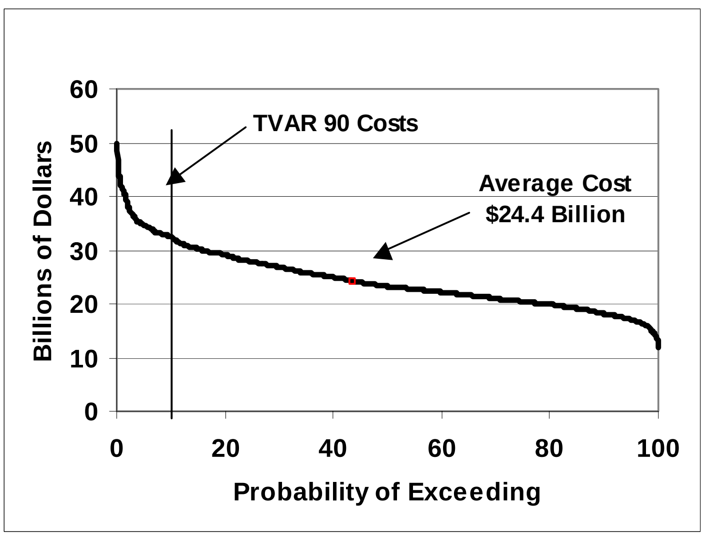


Figure 7-17: Distribution of Potential Costs

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.)

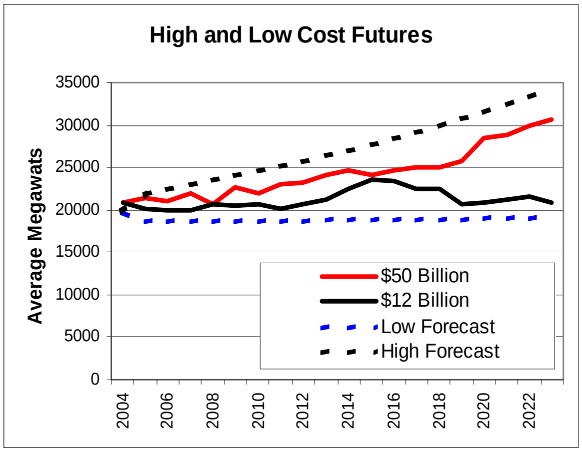
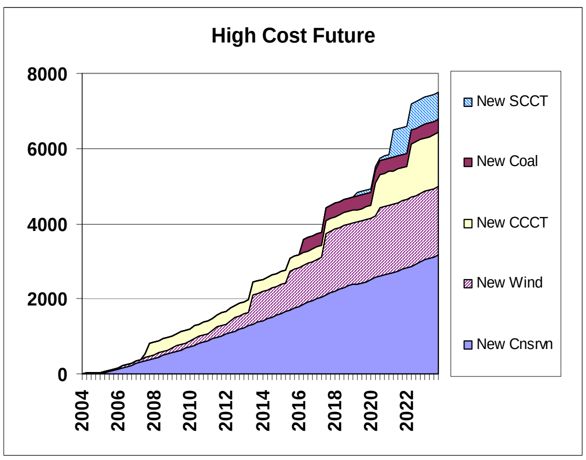
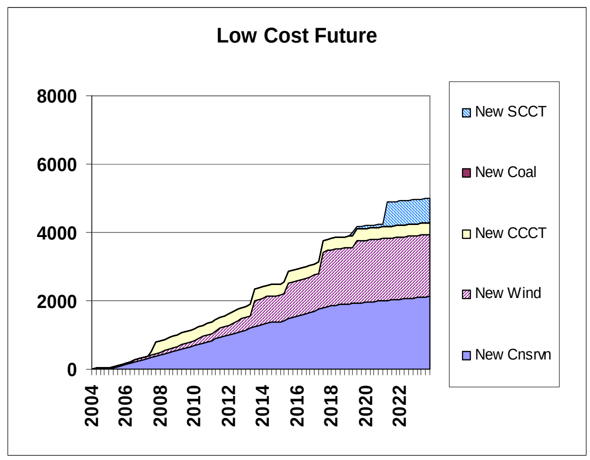


Figure 7-18:
Demand Growth for a High and Low Cost Future

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.

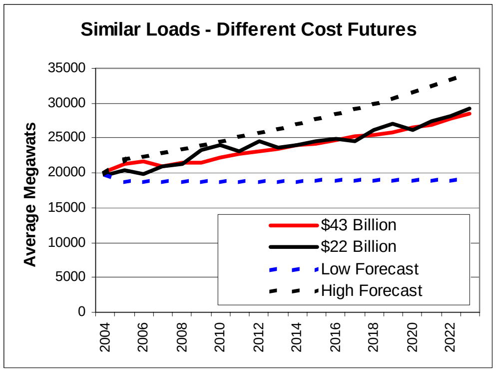
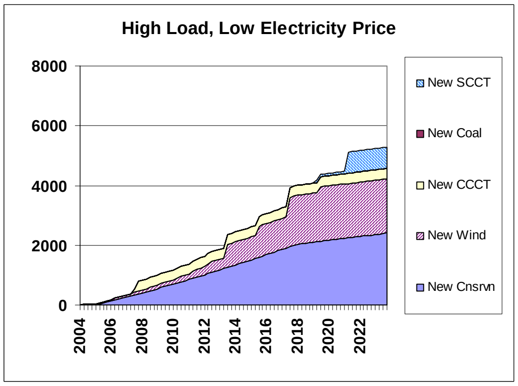
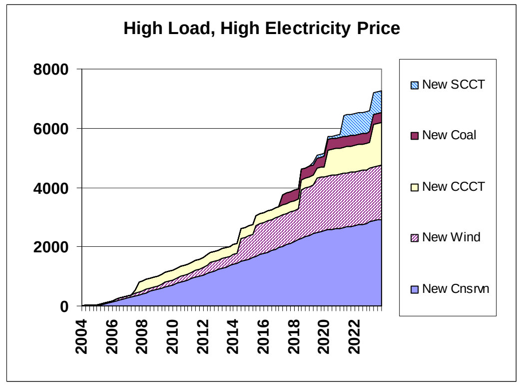


Figure 7-19:
Demand Growth for two Similar Cases with Different Costs

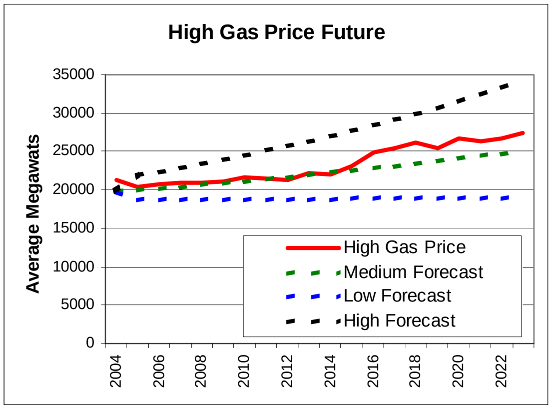
Resource In-Service Schedules for two Cases with Similar Demand but Different Costs

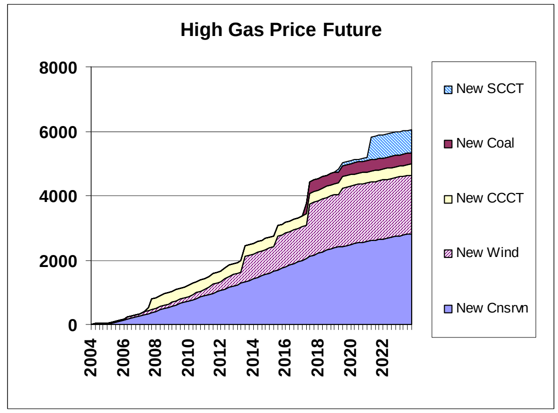




Average Cost - $ Billions	43
Average Growth Rate - %	2.0
Average Elect. Market Price - $/MWH	69
Average Gas Price - $/MMBtu	5.6
Average Carbon Tax - $/Ton CO2	4.6

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.

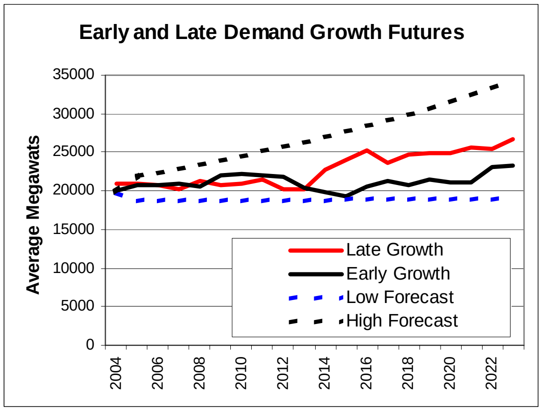
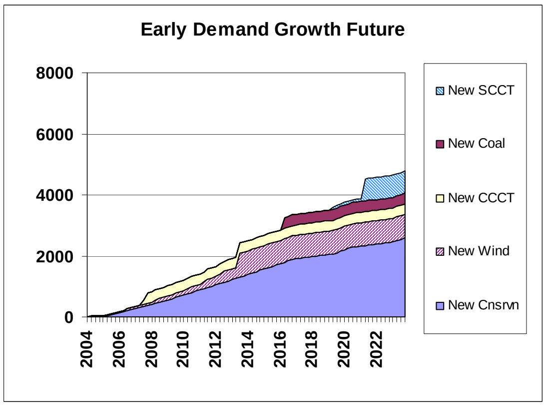
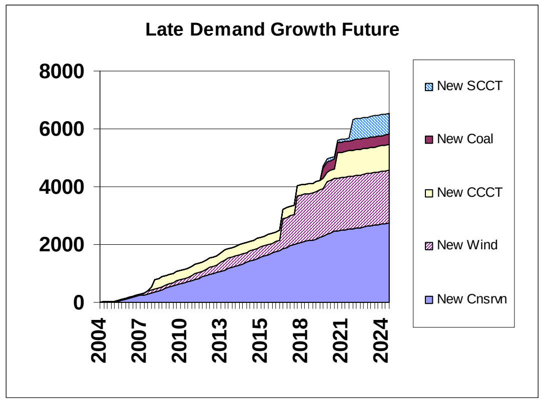


Figure 7-21:
Demand Growth for Early and Late Growth Futures

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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