Chapter 9: Developing a Resource Strategy

Introduction....... 1
Developing a Resource Strategy....... 2
Resource Strategy is Tied to the Act....... 2
Portfolio Selection....... 4
Model Portfolios....... 7
Interpreting Portfolio Costs....... 8
Low-Risk Portfolios....... 9
Interpreting Carbon Emissions and Costs....... 10
Sources of Uncertainty....... 11
Wholesale Power Prices....... 11
Load Uncertainty....... 13
Fuel Prices....... 13
Hydropower Generation....... 14
Resource Construction Costs....... 14
Climate Change and Carbon Emission Goals....... 16
Plant Availability....... 18
Renewable Energy Production Incentives....... 18
Renewable Energy Credits....... 19
Other Assumptions....... 19
Existing Renewable Portfolio Standard Resources....... 20
Forced-in Renewable Portfolio Standard (RPS) Requirements....... 22
Conservation from New Programs, Codes, and Standards....... 23
Independent Power Producers' (IPP) Resources....... 24
New Generating Resource Options....... 24
System Flexibility and Capacity Requirements....... 25

INTRODUCTION

This chapter describes the Council's treatment of risk in its planning analysis. In particular it describes scenarios that use the Council's regional portfolio model. This computer model simulates the development and operation of the region's power system in an uncertain world.

The Council's plans always have recognized uncertainty. The Fifth Power Plan (May 2005), however, was the first of the Council's plans that used the portfolio model to analyze strategies over hundreds of futures.

The chapter describes the model's approach to evaluating and selecting portfolios. It discusses the interpretation of the results of testing thousands of portfolios against 750 futures. The chapter then describes each of the sources of uncertainty that are included in the portfolio model for the sixth plan. The chapter concludes with a discussion of several issues unrelated to sources of uncertainty, such as how peak-power requirements are accounted for in the plan's analysis.

DEVELOPING A RESOURCE STRATEGY

Risk assessment has been central to Council planning since the first power plan. The Council's resource portfolio and forecasts must, by statute, address regional requirements over the next 20 years. However, reliably forecasting factors on which the plan relies is difficult, if not impossible. Therefore, the Council must assess cost and risk, both to the power system and to the environment, under significant uncertainty.

Earlier plans looked at an array of uncertainties and sources of risk. Load uncertainty, fuel price uncertainty, and hydro generation variability figured prominently in the conclusions of the plans. 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 also has valued “optioning” generating resources. Optioning refers to carrying out pre-construction activities and then, if necessary, delaying construction until conditions favor going ahead.

In the Fifth Power Plan, the Council extended its risk assessment and management capabilities. It developed a computer model that enabled the Council to look at decisions made without the perfect foresight that most models assume. The scenarios broadened the scope of uncertainty. New uncertainties included those associated with electricity market price, aluminum smelter loads, carbon-emission penalties, tax credits, and renewable energy credits. Scenarios evaluated thousands of resource portfolios and captured the costs associated with portfolios that adapted to changing circumstances and alternative scenarios.

This sixth plan builds on the lessons and techniques of the fifth plan. Council scenarios now incorporate uncertainty about power plant construction costs and availability. Scenarios track carbon production using several new techniques, and the impact of carbon penalties moves to center stage. The representation of conservation and demand response continues to evolve.

The study and treatment of risk requires a suitable framework. The next section describes how uncertainty, cost, and risk bear on the selection of a resource portfolio.

Resource Strategy is Tied to the Act

The Council’s Power Plan identifies resource strategies that minimize the expected cost of the region’s electricity future. The Act calls for a plan that assures an “adequate, efficient, economical, and reliable” power supply. Efficient and economical are interpreted to mean economically efficient, and net present-value (NPV) system cost is arguably the best indicator of such efficiency.

The Council’s regional portfolio model (RPM) evaluates possible portfolios under 750 different possible futures. Each future is a distinct combination of conditions for carbon penalties, demand growth, electricity and fuel prices, hydroelectric generation, and other key sources of uncertainty. For each future, the values of each variable are specified hourly over the 20 years of a scenario.

The model uses the same set of 750 futures to evaluate each resource portfolio. The model selects a future before it begins its chronological simulation of a given resource portfolio. As the model moves forward through the scenario, it simulates the behavior and cost of every resource in the regional power system, including new resources in the specific portfolio being assessed. Once the model completes the last period in the scenario, it computes the net present value of the costs for that resource portfolio under that future. It then selects a different future and starts over at the beginning of the scenario. Only after a resource portfolio has been evaluated under all 750 futures and a distribution of net present-value costs has been constructed does the model consider a different resource portfolio.

The expected cost of meeting the region's requirements gives us an idea of the most likely cost outcome. Most futures will cluster around this value. Comparing average net present-value system costs gives us an indication of which portfolio is ***most likely*** to achieve the Act's goal of an economically efficient system.

Special care is exercised in using the expected costs from this model, however. The section below, **Interpreting Portfolio Costs**, discusses this issue in more detail.

A "good" resource plan, according to the Act, is one that is economically efficient and has low net present value. But a plan certainly would be considered unsuccessful if it failed to meet the other requirements of the Act, adequacy and reliability. Consequently, the Council's regional portfolio model screens out resource portfolios that do not prove adequate and reliable. That leaves, however, very many portfolios, including ones that are overbuilt and quite expensive. It stands to reason that a portfolio that met the other requirements of the Power Act still would be considered unsuccessful if it resulted in a ***high*** net present-value cost to the region.

Knowing that forecasts will be wrong and that the future that actually unfolds may be among those in which our plan performs poorly, what is the best course of action? Ultimately, there is only one irreversible set of conditions. Risk-averse decision-makers will try to find portfolios that minimize the chance of high costs.

One approach to finding such a resource portfolio is to test portfolios under many distinct, feasible conditions and note the worst outcomes for each resource portfolio. Different resource plans, after all, will perform poorly under different circumstances. However, ***the*** worst outcome is not a good risk measure because its cost can be limitless. The "likely" of the worst outcomes is better behaved. These ideas and concepts are reflected in the Council's risk measure.

The Council's risk measure, TailVaR_{90}, is the average of the highest 10 percent of the net present-value cost outcomes associated with a given portfolio across the 750 futures. To the extent the Council wants to minimize the likely cost of the future energy system and is indifferent to risk, it would prefer a resource portfolio that minimizes expected or average cost. To extent the Council is risk averse, it would tend to select a resource portfolio that may have higher expected cost but lower risk.

Using these definitions of cost and risk, therefore, maximizes the chance of identifying portfolios that achieve the Act's objectives. Such a resource portfolio is likely to be lowest-cost among those that minimize the chance of high power costs, even under the worst circumstances.

Portfolio Selection

To understand the Council's approach requires a little background. It is useful to expand on the concepts introduced in the previous section. Some familiarity with the meaning of several terms, as the Council uses them, is also helpful.

A ***future*** is a specific combination of values for uncertain variables, specified hourly over the 20-year planning period. For the Council's work, a future will be a specific sequence of hourly values for each uncertainty. A future is hourly electricity requirements for 20 years, combined with hourly electricity prices for 20 years, combined with hourly (or daily) natural gas prices for 20 years, and so forth. The number of sources of uncertainty considered in Council scenarios would render the enumeration here unwieldy, but the next section describes them generally.

Given a particular future, the primary measure of a portfolio is its net present-value total system cost. These costs include all variable costs, such as those for fuel, variable operation and maintenance (O&M), and long- and short-term market purchases. These costs also include the fixed costs associated with investment in new resources and with their operations and maintenance. The present value calculation discounts these future costs to September of 2009 and states them in constant 2006 dollars. Discounting and other financial assumptions are discussed in Appendix N of the plan.

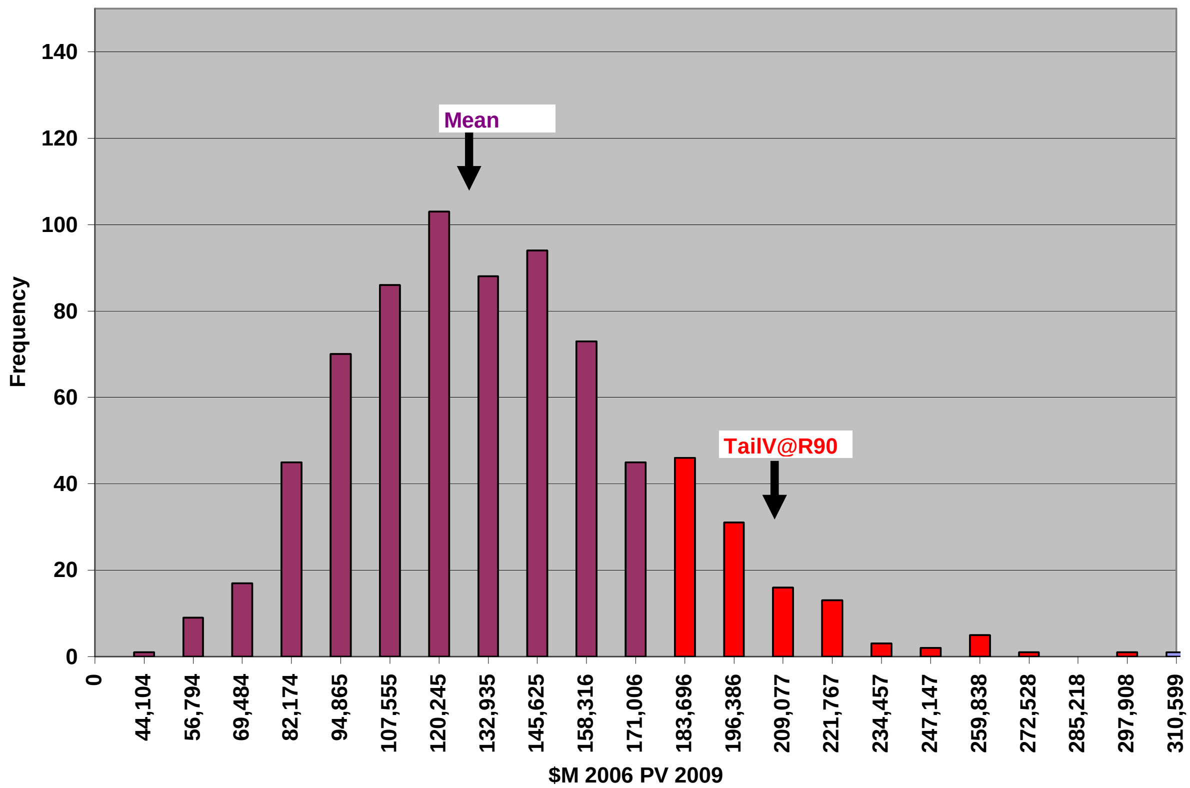
The futures differ significantly one from the other. While some planners would base future uncertainty on historical patterns, the Council recognizes that future markets and other sources of uncertainty rarely resemble the past. Some would refer to a Council future as a scenario. In the Council's modeling, futures typically include some historically unprecedented paths for prices, loads, and other variables. A small number may have an unlikely but not impossible future behavior.

The Council's treatment of uncertainty also reflects the potential for a larger pool of contributing factors than history provides. The model uses larger variation and weaker relationships among sources of uncertainty to achieve this effect. Past relationships often depend on markets, technologies, regulations, and other circumstances that could change in the future. The introduction of reserve-margin standards and renewable-portfolio-standard legislation in California, for example, has changed the traditional relationship between natural gas price and wholesale electricity price. Over the last 30 years, combined-cycle combustion turbines filled the role of providing new energy and capacity. Fundamental market economics assert that this role imposes a relationship between electricity prices and natural gas, the fuel that combustion turbines burn. Regulatory changes are upsetting that relationship. Renewables, built for purposes other than reducing expected cost or making a profit, are displacing combustion turbines. Non-renewable resources, added for reliability and flexibility, are also contributing. These innovations are changing the rules of the market.

Larger variation and weaker relationship among uncertainties in the Council's model therefore provide an opportunity to better understand the consequences of technological innovation, legislative and regulatory initiatives, transformation of markets, and other "unforeseeable" events. Combining futures in unlikely ways, moreover, reveals how different sources of uncertainty can combine to bring extraordinary risk. The next section describes the nature of specific sources of uncertainty.

The effect of different futures on the cost of a portfolio produces a distribution of portfolio costs. This distribution is the source of expected cost and risk attributed to that portfolio. Figure 9-1 represents the number of times the net present value cost for a single portfolio under all futures fell into specific ranges or "bins." That is, each bin is a narrow range of net present-value total system costs.

Figure 9-1: Example of a Portfolio Cost Distribution



Source: "Costs Illustrated.xls", worksheet "distribution"

Figure 9-1 is an example of the cost distribution for a ***single*** resource portfolio. Each resource portfolio will have a distinct distribution like the one in the figure.

Because a simulation of a particular resource portfolio typically uses 750 futures, the resulting distributions can be complicated. Representative statistics make the task of capturing the nature of a complex distribution manageable.

The average of the distribution provides an idea of the most likely cost outcome for this resource portfolio. Comparing average net present-value system costs between two portfolios gives us an indication of which portfolio is most likely to have the lowest cost.

The ***measure of risk*** that the Council adopted is TailVaR_{90}. Briefly, TailVaR_{90} is the average value for the worst 10 percent of outcomes.[1] It belongs to the class of "coherent" risk measures that possess special properties. These properties assure the measure reflects diversification benefits of resources in a portfolio. Coherent measures capture the magnitude and likelihood of

[1] See Appendix P of the Fifth Power Plan for a more detailed discussion of this risk measure and a comparison with other risk measures.

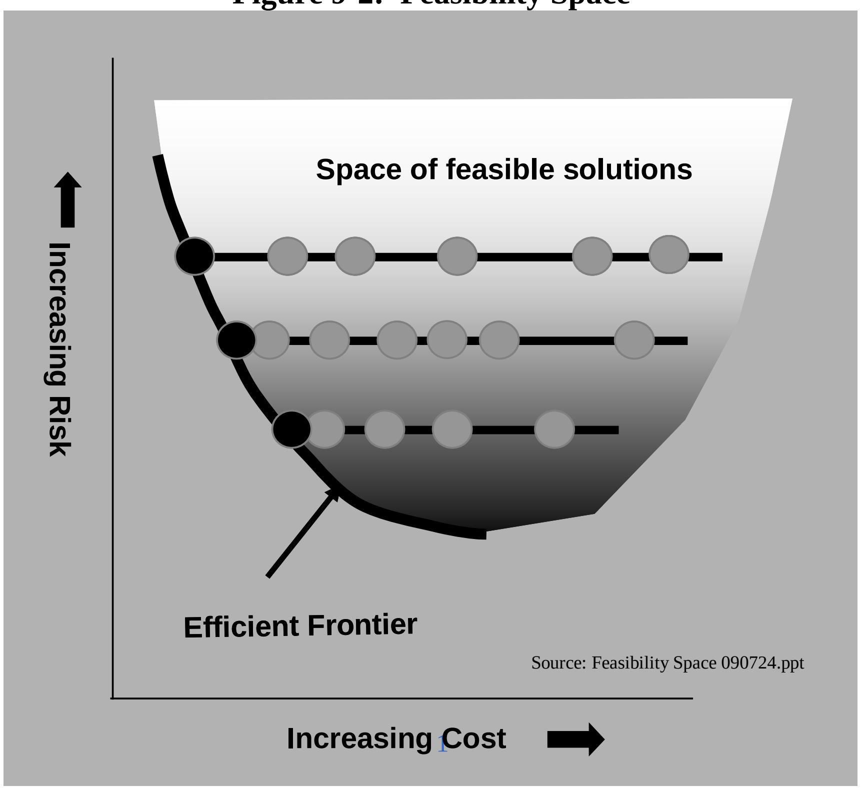
bad outcomes, rather than the predictability of, or the range of distribution for, an outcome. As mentioned above, use of $TailVaR_{90}$ is also consistent with avoiding high-cost outcomes.

Using these two statistics, each portfolio is associated with a point on a graph. The horizontal axis measures the portfolio's cost and the vertical axis measures the portfolio's risk. This way, a large number of resource portfolios can be compared on these two measures. A typical scenario evaluates 2,000 to 5,000 possible portfolios. The set of points corresponding to all portfolios is a ***feasibility space***, an illustration of which appears in Figure 9-2.

For each level of risk, there is a level, horizontal line passing through the feasibility space. The left-most portfolio in the feasibility space on that line is the least-cost portfolio for that level of risk. The ***efficient frontier*** of the feasibility space will contain only least-cost portfolios.

Because the Council typically evaluates thousands of portfolios, the efficient frontier permits the Council to narrow its search, typically to a fraction of one percent of these portfolios. It does so without invoking weighting factors or other, more problematic schemes that have been used to assess decisions with multiple objectives.

Figure 9-2: Feasibility Space



The Council's approach to resource planning could be called "risk-constrained, least-cost planning." Given any level of risk tolerance, the efficient frontier finds portfolios that achieve that level at the lowest cost. In this sense, it is comparable with traditional utility integrated resource plans (IRPs), also referred to as "least-cost" plans. If risk is ignored, the "least-cost" plan is the upper-left-most portfolio on the efficient frontier.

Risk often stems from short-lived events. Again, a measure that relies on net present-value costs may miss this kind of risk. Consequently, additional study of portfolio behavior over time is necessary. An example of the evaluation of portfolio risk in particular futures appears in Appendix J. The section ***Low-Risk Portfolios***, below, discusses risk in more detail.

Model Portfolios

The Council's resource portfolio does not look like a traditional firm resource plan to meet firm electricity demand. For example, it does not contain completion dates for new resources that will just meet load growth when needed.

The Council's definition of a resource portfolio consists of two elements. For most conventional resources, the portfolio specifies the option dates for specific types and amounts of generating resources. A resource is optioned when the design, siting, and licensing have been completed and it is ready for construction.

The second element of the portfolio consists of policies for conservation and demand response. Policies include cost-effectiveness "adders" or premiums over wholesale electricity market price for conservation acquisitions. For demand response, the policy consists of implementing one of several prescribed schedules for irrigation, heating, cooling, and other programs. These schedules specify the number of megawatts implemented at different times for each program over the 20-year scenario horizon.

The option schedules, conservation premiums, and demand-response deployment schedules for portfolios that lie on the efficient frontier are determined through a computerized search process. The model initially tries random portfolios, such as one where no resources can be added, one where all resources are available for construction at their maximum build rate, and so forth. For each of these, performance is simulated under the 750 futures, and the resulting average cost and risk are observed. After several hundred portfolios have been evaluated, the computer discovers which schedules of resources and policy choices tend to lower average cost and risk. By trying modifications of the more successful portfolios, it attempts to minimize the cost of the power system at different levels of risk.

The reason for using a plan defined by earliest construction start dates lies with the nature of generating resource construction risk. A significant source of risk to the region arises from inaccurate forecasts of the need for or the value of a generating resource. Both building too ***few*** and too ***many*** resources can be expensive and wasteful. The Council's model reflects the reality that decision-makers never can be sure how the future will work out.

The ***opportunity*** to construct a resource is prescribed by a given resource portfolio. Given such an opportunity, the model makes a decision – in each period of each future – whether to proceed with construction. This decision to construct is based on what the model thinks about the eventual value of and need for that resource under that particular future and at that particular time. The model's decision pays no attention to (does not "know" about) what will unfold in subsequent periods under this future. The model computes requirements and costs chronologically under each future so the model's decision-making has only a notion of the past. Thus, the decision must be based only on what price and requirement trends have been up to that point.

Constructing a plant does not guarantee the plant will be economical. Just as in life, circumstances change without notice. The model makes forecasting mistakes in some futures, and the costs – due to delays, emergency purchases, overruns, shortages, and cancellations – associated with those mistakes are captured in the portfolio's net present-value costs. By this means, the model identifies resource portfolios with values that are less sensitive to assumptions about the future.

The conservation acquired and the generating resources constructed in a given portfolio will be different in each of the 750 futures. The construction of generating resources and the acquisition of conservation in each future therefore will depend on how that particular future unfolds.[2]

The resulting resource portfolio is one that addresses the risks inherent in the future, not one that has the lowest cost for one specific future. In a given future, portfolio resources will not necessarily cover their costs in the wholesale electricity market. Some will do very well in certain futures and poorly in others. This is particularly true with portfolios that are near the least-risk end of the efficient frontier, where the resources necessary to yield such low risk are so expensive to construct that they typically cannot cover their costs in the market. What determines whether a resource portfolio falls on the efficient frontier at the least-risk end is more determined by whether it reduces total cost in the worst futures. This often comes about by *reducing* market prices, which usually acts to *increase* the net cost of resources. Reducing market prices, however, also reduces the risk of expensive market purchases during times of unexpected need and thereby reduces expected cost.

A traditional resource plan cannot address such scenario risks. Alternative scenarios can be tested in a traditional sense. This gives an idea of how the ideal plan might change if the future turns out different. However, it will not show how best to prepare when it is not clear which future will occur.

Because the Council's power plan directly addresses risk, some aspects of its portfolio may look contrary to a traditional approach to resource plans. In traditional planning, new resources are stacked up against growing loads so that new resources are scheduled at a particular date to meet requirements. Uncertainty about requirements is considered by looking at different levels of load growth. Uncertainty about hydropower conditions is addressed by planning for only critical-water conditions. These are not necessarily the most efficient plans, however, and they are based on how the world works today. These plans typically do not consider changing policies that could dramatically affect the cost of different strategies.

The Council's plan recognizes, however, that it may be advantageous to develop a portfolio for simultaneous construction of different types of resources. In any given future, only one of these might be constructed. One consequence of this is that, from a traditional load/resource-balance perspective, the option schedule might suggest the power system would be overbuilt.

Interpreting Portfolio Costs

Future costs of the power system in the Council's regional portfolio model are expressed in traditional planning terms. They are the net present value of future power system costs that can

[2] Animated graphs that illustrate how selected plans perform under the 750 futures are available from the Council's website.

vary with resource choices made in each future for the portfolio. They include the operating cost of existing resources and the capital and operating costs of future resources. The capital costs of existing resources are sunk costs and are not affected by future resource choices.

An important distinction exists between the net present-value system costs shown in illustrations of the feasibility space and the ***optioning cost*** of a particular portfolio. The net present-value system costs include costs that are largely outside the control of decision-makers. They include, for example, carbon penalties and natural gas costs. Option costs are the costs for siting, planning, and licensing new generation. They also may include some above-market cost for conservation, depending on one's view. These costs, the optioning costs, ***are*** within the scope of what decision-makers control.

It is a common misinterpretation of the efficient frontier that the region is paying for the change in net present-value system costs to achieve the reduction in system risk represented by the frontier. The average cost and risk, however, are not like the cost and benefit in an economic study. Instead, they represent ***distinct attributes of the distribution of outcomes***. The decision-maker can pay the optioning costs of the resources, but optioning costs typically are a *fraction of a percent* of the average costs illustrated on the efficient frontier. Depending on the future that actually materializes over the next twenty years, the benefits of optioning resources can, on the other hand, be much larger than the average cost along the efficient frontier.

The expected costs in other studies are often meaningful because they reflect a value to which average costs will trend over time. For example, average hydrogeneration energy and cost are meaningful in utility-production cost studies. The Council's price forecasts, for example, are based on average hydrogeneration. This use of expected energy is meaningful precisely because, over time, the energy and cost will trend to those values, even though they may differ significantly in any given year. That is not the case for many of the uncertain variables in this model. In fact, most futures consist of prices and requirements that move progressively away from today's forecasts. This behavior is important to risk modeling, but it makes expected cost harder to interpret.

The expected costs from the feasibility space differ from those in certain economic studies, too, in that typically they include only costs relevant to the selection of a resource portfolio. The fixed costs of the existing system, for example, are not included. Any decisions to modify the ***existing*** system of resources, therefore, cannot be based only on these costs.

The efficient frontier is a screen for portfolios, based on their relative performance. Their relative performance, in turn, relies only on independent aspects of the portfolio's distribution of possible cost outcomes. These aspects should not be interpreted like traditional economic cost and benefit.

Low-Risk Portfolios

The Council looks beyond expected net present-value cost and risk in distinguishing among portfolios. Often, risk originates from short-term events within a future. For example spikes in market electricity prices such as occurred in 2000-2001 can create huge cost increases if the region is overly exposed to the market. These short-term events are not apparent in net present-value costs. The imposition of a high carbon penalty can lead to high-cost futures if the region has become overly reliant on electricity generated at plants that burn coal. The regional portfolio model is designed to assess such risks and help the Council build resource strategies that will help avoid the impacts of such events.

The portfolios along the efficient frontier are distinguished by cost and risk. At the low-risk end of the efficient frontier, a portfolio's behavior in its worst 10 percent of outcomes determines its selection. It follows therefore that the benefits of a low-risk portfolio are revealed in those futures. The events that transpire over time within futures determine how risky that future is and whether our risk metric is correctly identifying those futures. Principal sources of risk in those futures may suggest alternative risk-mitigation mechanisms.

Risk mitigation does not affect all futures equally. The average cost of the low-risk portfolio will be slightly higher, but it provides protection, similar to an insurance policy, against the most costly future events. Understanding why particular resources in the low-risk portfolio provide this protection yields insight into their value and into the kinds of futures that would be bad for the region under a given resource portfolio.

Other evidence of reduced risk is reduced rate volatility and reduced exposure to the wholesale power market during high-price excursions. These characteristics of portfolios along the efficient frontier were explored in more detail in the Council's Fifth Power Plan.[3] A discussion of the model's calculation of revenue requirements appears in Chapter 3 and Appendix O of the Sixth Power Plan.

In general, portfolios near the lower-risk end of the efficient frontier contain more resources and rely less on the wholesale power market. By building more resources and reducing price volatility, these low-risk portfolios are more consistent with regulatory preferences and utility planning criteria than the lower-cost but higher-risk portfolios.

Interpreting Carbon Emissions and Costs

A new measure of power system performance is the emissions of carbon dioxide from generating plants that burn fossil fuels. It is important because of various greenhouse-gas-reduction targets and proposed policies to price carbon emissions through a tax or a cap-and-trade system.

Because electricity is generated and transmitted between and among regions of the country, measuring carbon emissions in any one region is difficult. Estimating the emissions from an individual power plant is relatively straightforward. But electricity trading creates a variety of options for counting emissions. One option is to count only the emissions of power plants actually located in the Pacific Northwest. Another is to count, in addition, the emissions of power plants that are located outside the Pacific Northwest but whose output is contractually committed to serve Northwest loads. A third is to count the carbon content of all electricity used to serve Northwest loads. This requires adding an estimated carbon content of imported power and subtracting the estimated carbon content of exported power from Northwest emissions.

The rules for such accounting have not been established, and proposed rules often vary by state and region. Such calculations are further complicated by the fact that electricity that is traded in wholesale markets is not typically identified as coming from a particular plant or technology. For example, what carbon content should be attributed to exported power? Is power exported

[3] Northwest Power and Conservation Council. The Fifth Northwest Electric Power and Conservation Plan. Volume 2, Chapter 7.

from the Northwest free of carbon emissions because it is generated by hydroelectric projects, or does it have substantial carbon emissions because it is generated from the region's coal plants? Perhaps it should be considered free of carbon, because its price already reflects any carbon penalty paid by producers, directly or through re-dispatching of resources.

Because the accounting treatment is not settled, the Council's regional portfolio model reports carbon emissions in two different ways. One is based on generation located within, or contracted to, the Pacific Northwest (generation-based). The other is based on the consumption of electricity within the region (load-based).

For the purpose of calculating load-based carbon, the model assumes imported and exported power has the same amount of carbon -- 1,053 pounds of CO_2 per megawatt-hour of electricity generated. This corresponds to the number pounds of CO_2 per megawatt hour that a natural gas-fired combustion turbine would produce if it had a heat rate of 9,000 BTU per kilowatt-hour. This is typical of an older-generation gas-fired power plant. It actually is a proxy for the average carbon emissions across all generation in the Western Electricity Coordinating Council region on the short-run margin over an extended time period, such as a year. Northwest generation averages somewhat lower emissions, and surrounding areas average somewhat higher during periods when the Pacific Northwest is importing power. This amount of emissions does not reflect the fact that alternative carbon-control regimes may shift the effective carbon emissions. This assumption does have the advantage, however, of being simple and easy to understand. Moreover, it closely resembles the assumed carbon-emissions factor adopted by Washington State Department of Commerce[4] and the California Energy Commission.

SOURCES OF UNCERTAINTY

Risk resides with a utility's overall portfolio of requirements and resources, rather than with one resource, one requirement, or one kind of fuel. Moreover, uncertainty does not necessarily lead to risk. Thermal-based utilities view fuel-price uncertainty and the variation of hydropower generation much differently than do hydropower-based utilities. Modeling the uncertainties that are traditionally the primary sources of risk, however, is the first step in a process to understanding economic risks to the region.

Wholesale Power Prices

It would be difficult and expensive for an individual utility to exactly match electricity requirements and generation at all times. Therefore, virtually all utilities participate in the wholesale market, directly or indirectly, as buyers and as sellers. This is particularly so for regional utilities because the region's primary source of generation, hydroelectricity, is highly variable from month to month and year to year.

Whether a utility has surplus generation or needs to purchase power affects the magnitude and direction of change in costs to electricity consumers when wholesale power prices rise. That is, if the utility needs power and if electricity market prices go up, consumers' costs can go up. If

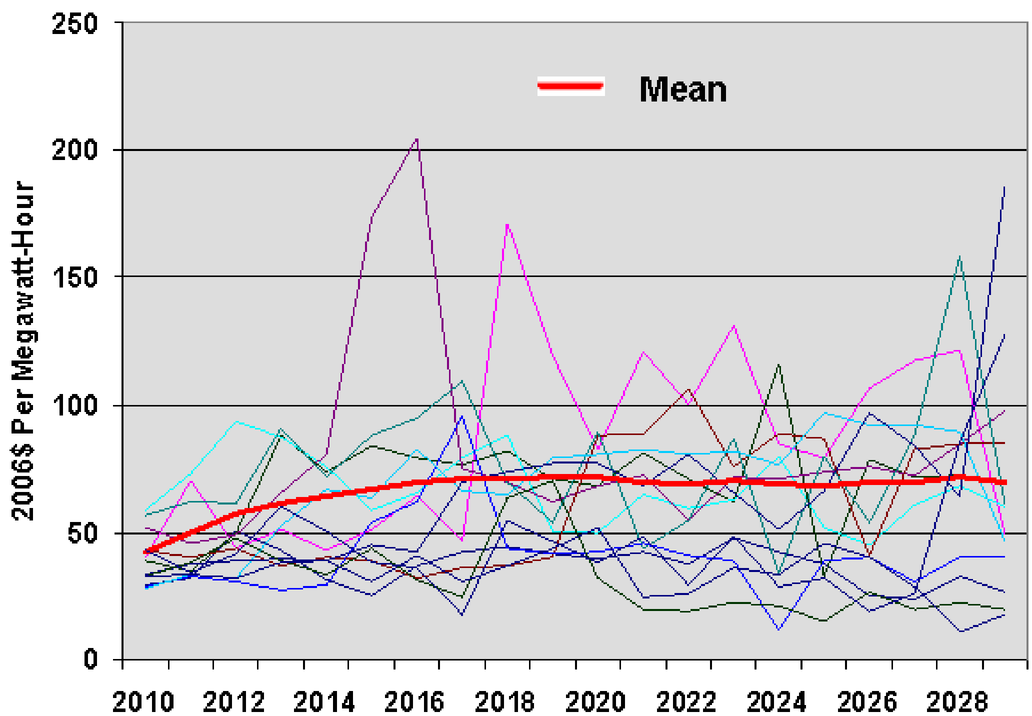
[4] See final opinion on California Energy Commission (CEC) Rulemaking 06-04-009, issued September 12, 2008, which calls for a default value of 1,100 pounds per MWh; and Tony Usibelli, Assistant Director, Washington Department of Community, Trade and Economic Development, to the CEC regarding this rulemaking, dated July 10, 2007, which uses 1,014 pounds per MWh.

the utility has surplus power to sell into the market, however, and electricity market prices go up, the larger revenues mean the utility's net electricity production costs will come down. This *reduces* the revenue the utility needs to collect from the consumers.

Disequilibrium between supply and demand is commonplace for electricity markets. 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 years. The resulting excursions from equilibrium prices can be large relative to the routine variation due to temperatures, fuel prices, plant outages, and hydro generation. These excursions are a significant source of uncertainty to electric power market participants, and they are therefore an important part of the Council's scenario analysis.

Figure 9-3 shows a sample of electricity price futures from among those that the Council's model uses. Description of the Council's electricity price forecast is in Chapter 2 and Appendix D. Typical of commodity price distributions, which are bounded below by the price of zero dollars per unit, the distribution in Figure 9-3 is quite skewed.

Figure 9-3: Electricity Price Future



Average prices for wholesale electricity over a quarter are capped at $325 per megawatt in the model. This value corresponds to the $400-per-megawatt-hour FERC price cap imposed over the Western power system. That is, the latter is the maximum hourly price the model would impute based on the former. Electricity prices rarely hit this level in the Council's portfolio model.

Load Uncertainty

The Council's model assumes a larger range of variation in loads than present in the Council's official load forecast for the sixth plan. The additional variation stems in part from seasonal and hourly patterns of load and from weather variation. A much larger source of variation, however, is uncertainty about changing markets for electricity, possible technology innovations, and excursions due to business cycles.

Figure 9-4: Load Futures

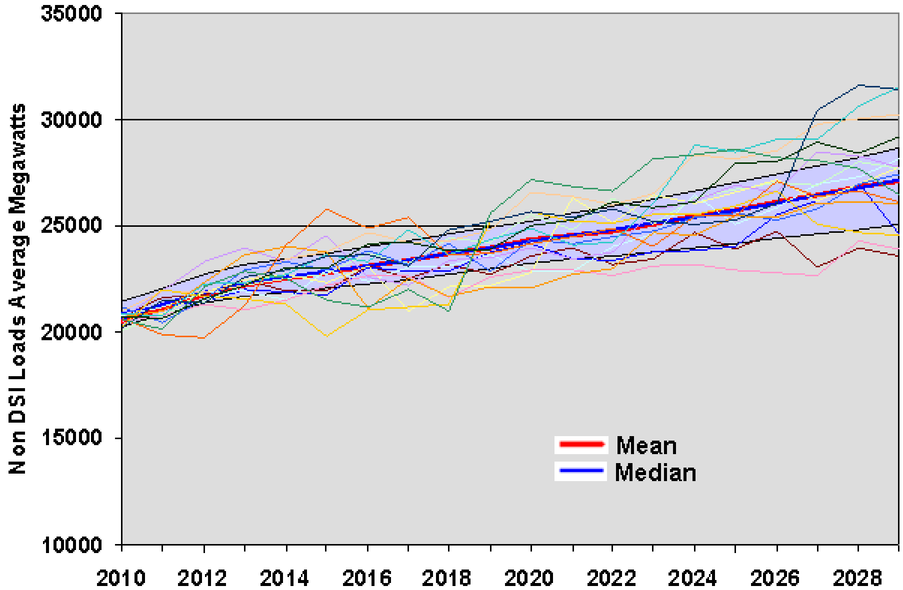


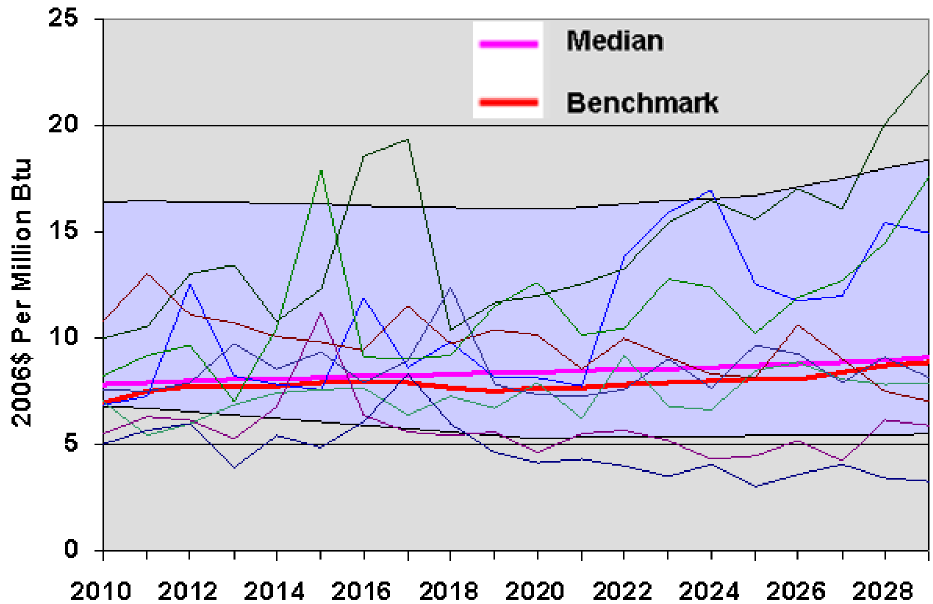
Figure 9-4 displays a sample of load futures from the Council's model simulations compared to the shaded trend forecast range. A detailed description of the Council's official load forecast and the treatment of aluminum smelter loads appears in Chapter 3.

Fuel Prices

The basis for uncertain natural gas price trends is the Council's fuel-price forecast range as described in Chapter 2 and Appendix A. In addition to uncertainty in long-term trends in fuel prices, the modeling representation uses seasonal patterns and brief excursions from these 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 9-5 illustrates some natural gas price futures from the portfolio model simulations (2006$).

As with electricity prices, the price distribution is quite skewed. The shaded area corresponds to the high and low ranges discussed in Chapter 2.

Figure 9-5: Gas Price Futures



Hydropower Generation

A 70-year history of streamflows and generation provides the basis for hydropower generation in the model. The hydropower generation reflects constraints associated with the NOAA Fisheries 2008 biological opinion. Moreover, scenarios evaluate resource choices assuming no emergency reliance on the hydropower system, even though such reliance might not violate 2008 biological opinion constraints.

In addition to meeting fish and wildlife requirements, hydropower operation must satisfy other objectives. These objectives include standard flood control, river navigation, irrigation, recreational, and refill requirements. All scenarios incorporate these constraints.

The modeling assumes no decline of output over the 20-year study period due to relicensing losses or other factors that might lead to capability reduction. Nor does it assume any increases due to deployment of removable spillway weirs or turbine upgrades. Chapter 10 does include, however, a study of the potential effects of removing the four Lower Snake River dams.

Resource Construction Costs

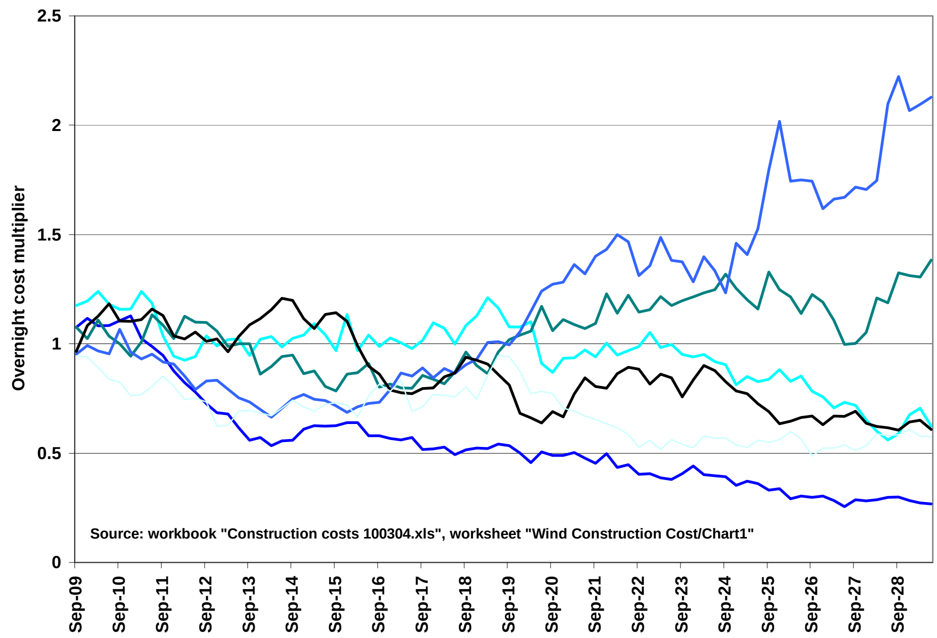
Recent resource development has revealed costs that are significantly higher than anticipated in earlier planning. The details of expected costs for resource technologies over time appear in Chapter 6. These expected costs, which typically trend downward over time, serve as the benchmark for resource construction cost futures the model uses to capture construction cost uncertainty. The Council's Generating Resource Advisory Committee assisted the Council in characterizing the types and likelihood of futures for construction costs.

The Council's model uses these futures to assess the likely future economic value of resources, among other things. Economic value is one aspect of the decision the model makes within a future whether or not to construct a resource.

Several cost futures for wind generation resources appear in Figure 9-6. Each future is a sequence of cost multipliers for "overnight" construction. They are applied to a figure of dollars per kilowatt of capacity for a wind plant to determine the effective overnight construction cost for that plant. The overnight construction cost is the total dollars spent over the plant's construction cycle, but it does not include any costs for financing or for delays in construction. Figure 9-6 therefore represents how the overnight cost for constructing a power plant will change over time. The model takes the cost available at the time of plant construction. The model then effectively places that cost in ratebase and customers continue to pay off the construction cost over the life of the plant. Subsequent changes in the multiplier have no effect.

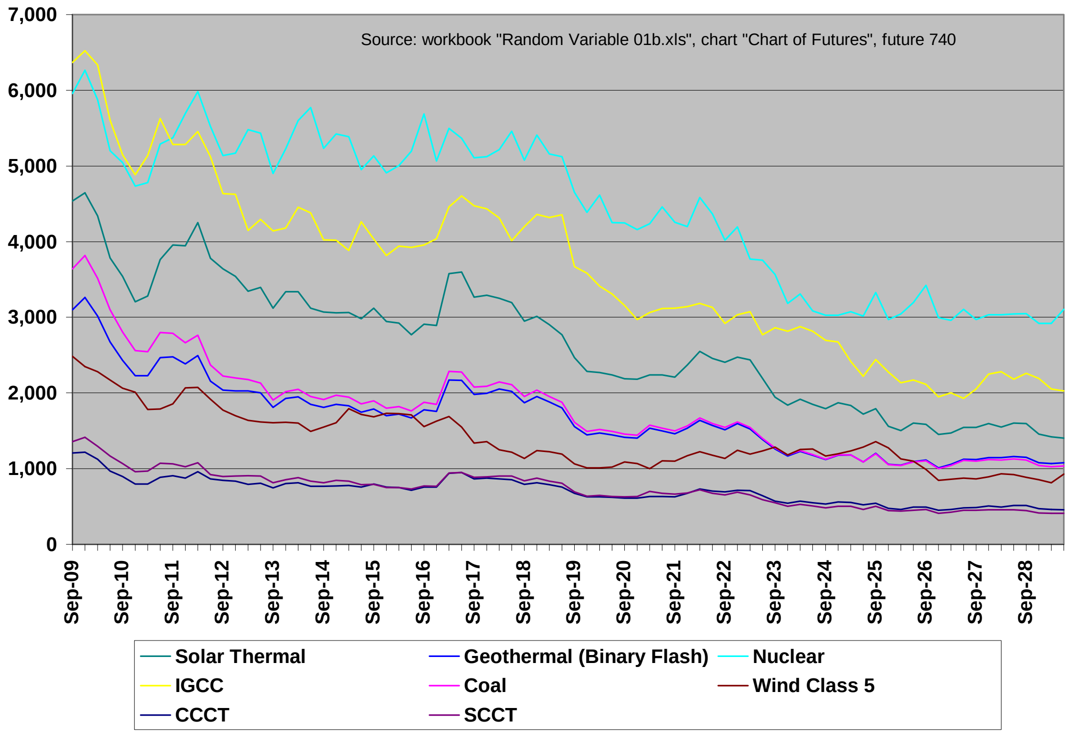
A trend of decreasing real cost from the highs in 2007-2009 is evident in Figure 9-6. This reflects the expected price decreases anticipated over the September 2009 – August 2029 period.

Figure 9-6: Construction Cost Futures for Wind Generation



An example of a ***single*** construction cost future for several generation technologies appears in Figure 9-7. This figure illustrates how construction costs generally move together through time, reflecting their shared cost components, such as steel, concrete, and labor. Appendix J provides a more complete description of probability ranges of costs over time for each resource in Figure 9-7.

Figure 9-7: Construction Cost Multipliers



Climate Change and Carbon Emission Goals

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 region could see control policy materializing at the federal or state level, or through means such as the Western Climate Initiative (WCI) in which Washington, Oregon, and Montana are participants.

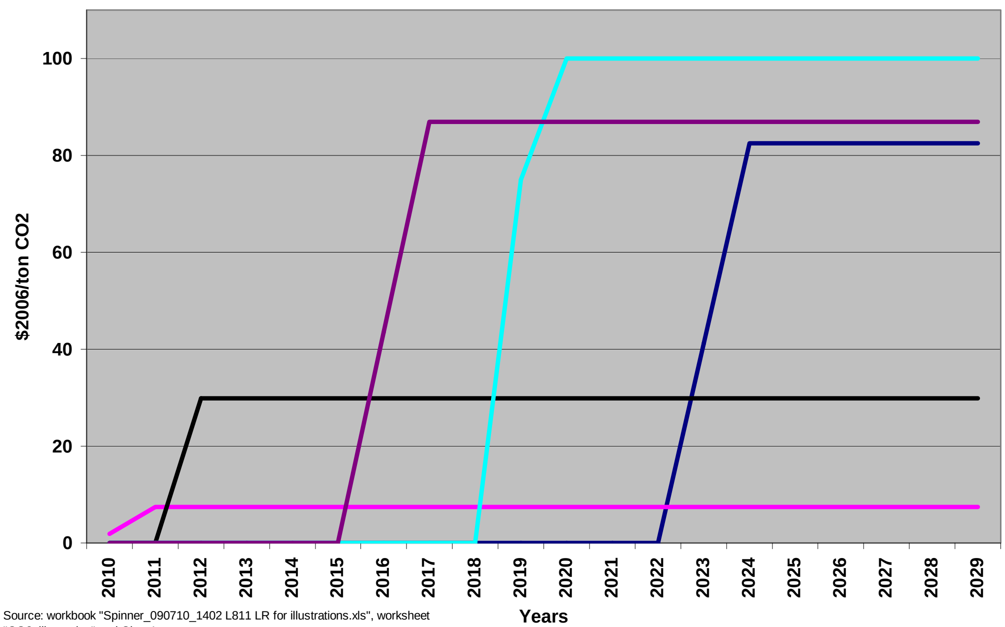
It is unlikely that reduction in carbon dioxide production can be achieved without cost. Consequently, future climate-control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to have been a successful approach to controlling sulfur oxides and may be used again for CO_2 production control. Alternatively, a carbon tax has the benefit of simpler administration and perhaps fewer opportunities for manipulation. It is also unclear where in the carbon-production chain – the source, conversion, or use – a control policy would be implemented. It is unclear what share of total carbon production the power-generation sector would bear or what would be done with any revenues generated by a tax or trading system. It is unclear which ratepayer sector will pay for which portion of any costs associated with a control mechanism.

The Council's scenarios use a fuel carbon-content tax as a proxy for the cost of CO_2 control, whatever the means of implementation. When considered as an uncertainty, scenarios represent carbon-control policy as a penalty (dollars per ton CO_2) associated with burning natural gas, oil, and coal.

The model keeps track separately of the two costs that arise from a carbon tax. There is a cost associated with any revenues generated by the tax. There is also a cost associated with alternative dispatch of resources. Separate accounting facilitates evaluation of the effects of a tax independent of assumptions regarding the use of the tax revenues.

Each carbon-penalty future is a step up to a random value, selected by the model, where it remains until the end of the study period (Figure 9-8 illustrates the penalty in a small handful of futures). The progression of carbon penalty over time is unlikely to resemble any of these futures. Nevertheless, using a large number of futures should provide a fair idea of the risk associated with most paths.

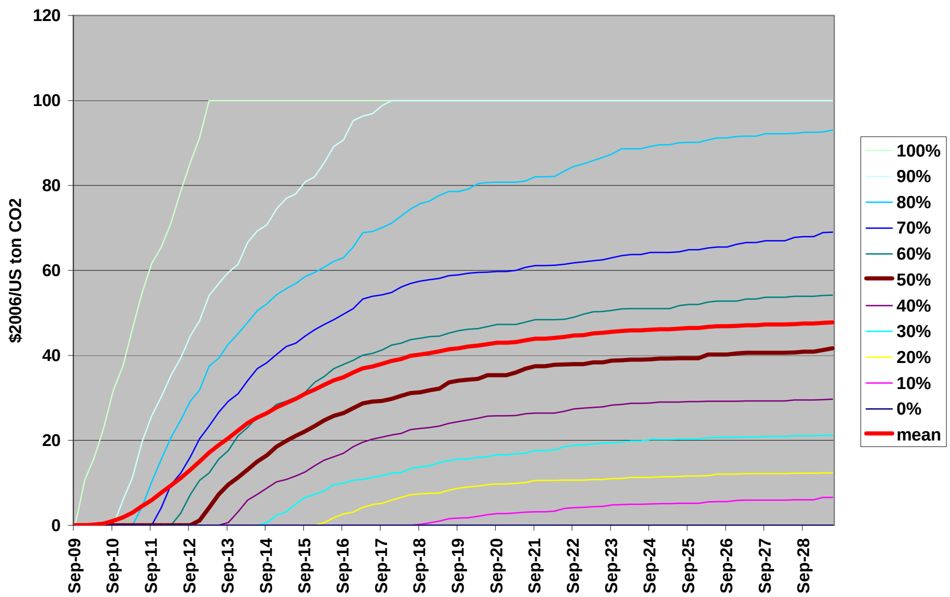
Figure 9-8: Samples on Individual CO_2 Penalty Futures



Source: workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "CO2_illustration" and Chart1

In the Council's carbon-risk scenarios, a carbon penalty can arise at any time. The modeled probability of such a penalty being enacted at some time during the forecast period is 95 percent. If a penalty is enacted, its value is selected from a uniform distribution between zero and $100 per ton (in 2006 dollars). The resulting probability of finding a carbon penalty at or below various levels in each period appears in Figure 9-9. The distribution indicates an even likelihood of seeing some positive carbon penalty around 2012. This assumption, recommended by the Council's Generation Resource Advisory Committee and adopted by the Council's Power Committee, is responsible for the shape of the distribution. The mean of the distribution over all futures rises gradually to about $47.50/ton of CO_2 by the June – August 2029 quarter. As discussed in Chapter 11, the distribution corresponds to the range of outcomes that EcoSecurities, Ltd., estimated for the Council.

Figure 9-9: Deciles for Carbon Penalty



Source: workbook "New CO2 Distribution 090425.xls", chart "Carbon Distribution"

Preliminary analyses evaluated alternative carbon-penalty distributions. Reducing the penalty in each future by half results in substantially the same resource plan for the first decade of the scenario as does the zero to $100 distribution.

There are mechanisms in addition to carbon penalties and trading programs to meet carbon-emission objectives. Scenarios considered displacement of existing resources with new renewables or more-efficient gas-fired plants. The Council also evaluated direct curtailment and retirement of existing coal-fired plants. The Council has not taken a position in favor of any particular approach to carbon reduction. Rather, the plan provides information and analysis on alternative approaches. Results of this analysis appear in Chapter 10.

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.

Renewable Energy Production Incentives

The production tax credit and its companion Renewable Energy Production Incentive were originally enacted as part of the 1992 Energy Policy Act. The intent was to commercialize wind and certain biomass technologies. Congress has repeatedly renewed and extended them.

The longer-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as the costs of qualifying resources become competitive. Moreover, federal budget constraints eventually may force reduction or termination of the incentives.

In the model, two events influence the value of the production tax credit over the 20-year study period. The first event is termination due to cost-competitiveness. The likelihood of termination peaks in about five years in the Council's model. The model provides, however, for the possibility of the credit remaining indefinitely or expiring immediately. The second event that modifies the credit in the Council's model is the advent of a carbon penalty. The value of the credit following introduction of a carbon penalty depends on the magnitude of the carbon penalty[5].

The Council did not want any reduction in the value of the production tax credit to exceed the advantage afforded renewables by a CO_2 penalty. Such an outcome would be contrary to the likely intent of a CO_2-control policy. This concern determines the value of the production tax credit in the model due to the magnitude of any carbon penalty that arises in a given future.

Production tax credits amounted to $15 per megawatt hour when first adopted and have escalated with inflation. The current value for wind, closed-loop biomass, and geothermal is $21 per megawatt hour. Investors receive credits only for the first 10 years of project operation. Council modeling scenarios use real, levelized values, however. The levelized value over a 20-year economic life would be about $9.10 in 2006 dollars.

Renewable Energy Credits

Power from renewable-energy projects currently commands a market premium, which can be unbundled from the energy and traded separately as renewable energy credits (RECs). REC value varies by resource and over time, like most commodities. This value reduces the cost of the power source if sold. In the Council's model, REC value varies in a manner similar to other commodities and differs by future.

The Council models the Montana, Oregon, and Washington Renewable Portfolio Standards (RPS). The RPS regulations of these states require an obligated utility to retain the REC associated with the power produced by the utility's renewable resource. That is, the utility cannot buy or build qualifying renewable power and then sell or trade the REC separately. While obligated utilities may sell RECs associated with resource surplus to their requirements, they may also bank the energy to meet future RPS needs. If this makes economic sense, the utility would also not sell the REC.

OTHER ASSUMPTIONS

This section discusses assumptions that are not treated explicitly as uncertainties. These assumptions include those about the treatment of renewable portfolio standard (RPS) resources,

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[5] If the carbon penalty is below half the initial value of the PTC, the full value of the PTC remains. 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. 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. 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. The Fifth Power Plan, which uses the same approach, has additional explanation and details.

conservation, independent power producers, recent resource additions to the existing system, and the treatment of flexibility and capacity requirements.

The plan discusses some assumptions thoroughly in other chapters or in the appendices. Consequently, their description does not appear in this chapter. In particular, Chapter 7 describes the treatment of transmission in Council analysis. Resources in the model include the cost of any incremental transmission required and the impact of transmission energy losses. Transmission constraints do not appear explicitly in the model. It is assumed that resources that do not have additional transmission cost can be located such that additional transmission is unnecessary. Finally, the model uses a 5-percent discount rate to equate costs occurring at different times, and this value is derived in Appendix N.

Existing Renewable Portfolio Standard Resources

Table 9-1 lists the 1,050 average megawatts of existing renewables. The table includes about 2,634 megawatts of wind that the region has completed or will soon complete. When evaluating the potential for wind generation in the region, this quantity – which is not included in any specification of new resource capability the model may select – must be considered.

Table 9-1: Base of RPS Resources

Project	Capacity (MW)	Service Year	Resource	Load	CA	MT	OR	WA
Biglow Canyon Ph I	125.4	2007	Wind	PGE			100%	
Biglow Canyon Ph II	149.5	2009	Wind	PGE			100%	
Broadwater	10.0	1989	Hydro	NWE		100%		
Clearwater Hatchery (Dworshak)	2.9	2000	Hydro	BPA			22%	78%
City of Albany (Vine St)	0.5	2009	Hydro	PAC	4%		74%	22%
Coffin Butte 1 - 5	5.2	1995	Biomass	Consumers			100%	
Combine Hills I	41.0	2003	Wind	PAC	4%		74%	22%
Condon	49.8	2002	Wind	BPA			22%	78%
DeRuyter Dairy	1.2	2007	Biomass	PAC	4%		74%	22%
Douglas County Forest Products	3.2	2006	Biomass	PAC	4%		74%	22%
Dry Creek Landfill	3.2	2007	Biomass	PAC	4%		74%	22%
Echo	44.6	2009	Wind	PAC	4%		74%	22%
Farm Power (Rexville)	0.8	2009	Biomass	PSE				100%
Foote Creek (BPA)	16.8	2000	Wind	BPA			22%	78%
Foote Creek (EWEB)	8.3	1999	Wind	EWEB			100%	
Foote Creek (PAC)	33.1	1999	Wind	PAC	4%		74%	22%
Freres Lumber	10.0	2007	Biomass	PAC	4%		74%	22%
Georgia-Pacific (Camas)	52.0	1995	Biomass	PAC	5%		95%	0%
Georgia-Pacific (Wauna)	27.0	1996	Biomass	BPA			100%	0%
Goodnoe Hills	94.0	2008	Wind	PAC	4%		74%	22%
H.W. Hill (Roosevelt Biogas) 1 - 5	10.5	1999	Biomass	Klickitat				100%
Hampton Lumber	7.2	2007	Biomass	Snohomish				49%
Harvest Wind	98.9	2009	Wind	Various			20%	80%
Hay Canyon	100.8	2008	Wind	Snohomish				100%
Hopkins Ridge	150.0	2005	Wind	PSE				100%
Judith Gap	135.0	2006	Wind	NWE		100%		
Klondike I	24.0	2001	Wind	BPA			22%	78%
Klondike II	75.0	2005	Wind	PGE			100%	
Klondike III (BPA)	50.0	2007	Wind	BPA			22%	78%
Klondike III (EWEB)	25.0	2007	Wind	EWEB			100%	
Klondike III (PSE)	50.0	2007	Wind	PSE				100%
Leaning Juniper	100.5	2006	Wind	PAC	4%		74%	22%
Marengo I	140.4	2007	Wind	PAC	4%		74%	22%
Marengo II	70.2	2008	Wind	PAC	4%		74%	22%
Martinsdale (Two Dot)	2.8	2004	Wind	NWE		100%		
McNary Dam Fish Attraction	7.0	1997	Hydro	N. Wasco			50%	
Nine Canyon	63.7	2002	Wind	COU				100%
Portland Habilitation	0.9	2008	PV	PGE			100%	
ProLogis	1.1	2008	PV	PGE			100%	
Puyallup Energy Recovery Company (PERC) 1 - 3	2.8	1999	Biomass	PSE				100%
Qualco	0.5	2008	Biomass	Snohomish				100%
Rock River I	50.0	2001	Wind	PAC	4%		74%	22%
Rough & Ready Lumber	1.2	2007	Biomass	PAC	4%		74%	22%
Round Butte	339.0	1964	Hydro	PGE			15%	
Short Mountain 1 - 4	2.5	1993	Biomass	Emerald			100%	
Sierra Pacific (Aberdeen)	10.0	2003	Biomass	Grays Harbor				56%
Sierra Pacific (Fredonia)	28.0	2007	Biomass	SMUD, SCL	82%			11%
South Dry Creek	1.8	1985	Hydro	NWE		100%		
Stahlbush Island Farms	1.6	2009	Biomass	PAC			100%	
Stateline (AVA)	35.0	2001	Wind	AVA				100%
Stateline (BPA)	90.0	2001	Wind	BPA			22%	78%
Stateline (SCL)	175.0	2001	Wind	SCL				100%
Tiber-Montana	6.0	2004	Hydro			100%		
Tieton	13.6	2006	Hydro	EWEB			100%	
Two Dot	0.9	2004	Wind	NWE		100%		
Vansycle Wind Energy Project	24.9	1998	Wind	PGE			100%	
Weyerhaeuser (Springfield) 4 (WEYCO)	25.0	1975	Biomass	EWEB			100%	
Wheat Field	96.6	2009	Wind	Snohomish				100%
White Creek (Benton PUD)	3.0	2007	Wind	Benton PUD				100%
White Creek (Cowlitz)	94.0	2007	Wind	Cowlitz				100%
White Creek (Emerald)	15.0	2007	Wind	Emerald			100%	
White Creek (Franklin)	10.0	2007	Wind	Franklin				100%
White Creek (Klickitat)	53.0	2007	Wind	Klickitat				100%
White Creek (Lakeview)	2.0	2007	Wind	Lakeview				100%
White Creek (Snohomish)	20.0	2007	Wind	Snohomish				100%
White Creek (Tanner)	4.0	2007	Wind	Tanner				100%
Wild Horse Wind	228.6	2006	Wind	PSE				100%
Wild Horse Expansion	44.0	2009	Wind	PSE				100%
Wolverine Creek	64.5	2005	Wind	PAC	4%		74%	22%

Source: "Plan 6\Power Plan Documents\Chapter 9 DevStrategy (previously chapter 8)**Renewables for the RPS.xls**"

Forced-in Renewable Portfolio Standard (RPS) Requirements

Montana, Oregon, and Washington, like many other western states, have legislated goals that obligate utilities to meet a prescribed portion of their energy loads with renewable generation according to schedules that extend to 2025, in the case of Oregon. When modeled as an uncertainty related to regional load growth, the Council assumes obligated utilities meet 95 percent of their nominal RPS goals. This representation captures the possibility that utilities will face obstacles to meeting their nominal targets. One mechanism, for example, that might give rise to not meeting targets is the "opt-out" provision. This provision in legislation excuses utilities from meeting their targets when meeting the requirements would cause significant rate increases.

Adoption of RPS legislation by other states, in particular California, is expected to affect the region primarily through the expected price of wholesale power. The anticipated change in wholesale electricity prices due to this effect is incorporated in Council modeling, as is the uncertainty around such change.

Renewable resources constructed to meet RPS requirements do not receive a cost reduction due to the sale of renewable energy credits (RECs). When regional utilities acquire renewables to meet their state's requirements, they must retain any RECs associated with the resource. This has the effect of increasing the cost of the resource relative to what renewable costs would have been had the utility been able to sell the RECs. Utilities, however, may bank RECs that are not used toward meeting RPS requirements. These credits may be applied toward future obligations. States differ in the policy regarding how long RECs may be banked and under what conditions.

Modeling does not include wind or geothermal explicitly when an RPS is assumed. Earlier studies suggest that renewables will not be constructed for economic reasons earlier than or in greater quantity than required by these standards. In scenarios that assume RPS requirements disappear, wind and geothermal are available for the model to select.

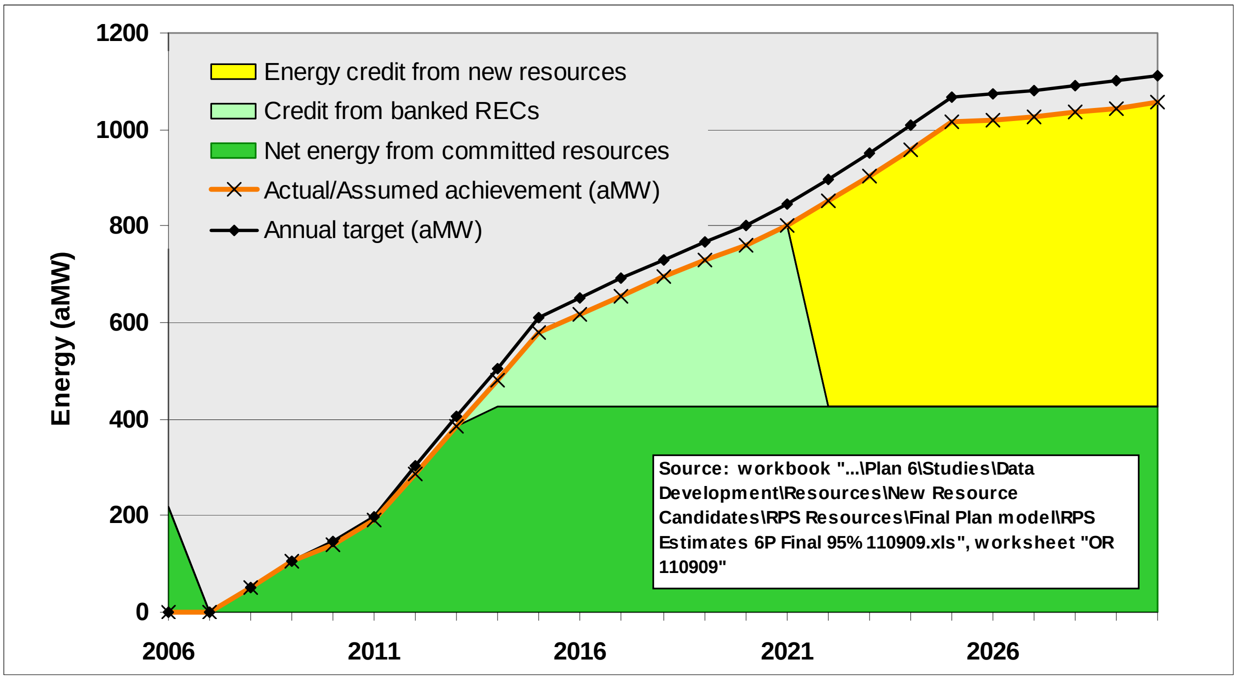
Figure 9-10 provides an example of how existing RPS resources, banked RECs, and new RPS resources play out for one state under a particular future. This particular example is for the state of Oregon. Obligated utilities' target portions of energy sales, after conservation, comprise the heavy, dotted line at the top of the graph. Targets are specified only in a handful of years, so targets for other years are interpolated. Next, it is assumed that obligated utilities achieve only 95 percent of target amounts. The next line down reflects that assumption. Resources that currently qualify for renewable energy credits are illustrated in dark green.

Based on the current level of RPS development and state policy, credit balances are calculated. In Oregon, credits do not expire. Renewable energy credit balances for Washington and Montana must be updated every year to account for expiring credits, and these two states have different requirements regarding the how soon credits expire. It is assumed that if credits would expire quickly and would not be used, they are sold to offset the cost of the resource.

The light green area corresponds to banked renewable energy credits. While RECs do not expire in the case of Oregon, they do get used. RECs are denominated in megawatt-hours. This means that once a REC is used to meet a megawatt-hour of customer energy load in some year, it goes away. Consequently, the light green area ends when energy produced by utility renewable resources is insufficient to meet the RPS energy target and Oregon utilities have used up their banked credits.

The energy corresponding to this net requirement, after banked credits are used up, is illustrated in yellow. This energy is assumed to be largely wind but also geothermal, biomass, small hydro, and photovoltaic solar. Because the energy is dominated by wind, wind operating and construction costs are used for new renewables. These costs are subject to the same construction cost uncertainty as are wind generation resource modeled without RPS requirements. The new resources are also expected to have value derived from sale in the wholesale power market, whereas credits have no associated cost or value of this sort.

Figure 9-10: RPS Source Development



Conservation from New Programs, Codes, and Standards

Conservation due to existing codes and standards is incorporated in the Council's load forecast. An example of such a code is the mandated conversion to energy-efficient lighting throughout the nation beginning in 2012. Such conservation is excluded from programs that the model may select going forward. New conservation is subject to severe constraints on development in the model early in the scenario period. Full penetration of lost-opportunity conservation is assumed to develop slowly over the next decade.

A large amount of discretionary conservation, however, exists at prices far below the current wholesale power price. Left unconstrained, the model would add as much as 2,000 average megawatts of this conservation immediately. While difficult to quantify, utilities have budget constraints that, given no other consideration, would significantly limit how quickly the region can acquire this conservation. The Council, with the guidance of the Conservation Resource Advisory Committee and the Regional Technical Forum, chose a rate of acquisition that it considers aggressive but achievable: development of discretionary conservation at the rate of 160-average-megawatts-per-year. These constraints are discussed in Chapter 4 and Appendix E.

Independent Power Producers' (IPP) Resources

Independent power producers provide depth to wholesale markets but do not mitigate regional ratepayer costs or risks. IPP plants not currently under contract provide energy for the regional wholesale market. The IPP owners, however, receive the benefits of any energy sold, not the region. There are about 3,335 megawatts of IPP generating capacity 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. A list of the IPP generation modeled in Council scenarios appears in Table 9-2.

Table 9-2: Independent Power Producers

Plant name	Uncommitted share	Project Owner	January Capacity (MW)
Big Hanaford CC1A-1E	100%	TransAlta	233.4
Centralia 1	85%	TransAlta	625.1
Centralia 2	100%	TransAlta	625.1
Grays Harbor Energy Facility (Satsop)	100%	Invenergy (dba Grays Harbor Energy)	611.7
Hermiston Power Project	100%	Calpine, dba Hermiston Power Partners	498.7
Klamath Cogeneration Project	100%	Iberdrola Renewables	451.7
Klamath Generation Peakers 1 & 2	100%	Iberdrola Renewables	47.5
Klamath Generation Peakers 3 & 4	100%	Iberdrola Renewables	47.5
Lancaster (Rathdrum CC)	100%	Cogentrix	264.4
Morrow Power	100%	Morrow Power (Subsidiary of Montsano Enviro Chem Systems)	23.7
		Discounted total	3334.9

Source: workbook "Table of IPPs 100118.xls", worksheet Sheet2

New Generating Resource Options

Resources explicitly considered include natural gas combined-cycle gas turbines, natural gas simple-cycle gas turbines, wind-power plants, and gasified coal combined-cycle combustion turbines. A complete list appears in Table 9-3, below.

Table 9-3: New Resource Candidates

- Conservation
  - Discretionary conservation limited to 160 average megawatts per year
  - Phased in up to 85-percent penetration maximum
- CCCT (415 MW) available 2011-2012
- SCCT (85 MW Frame GT) available 2012
- Wind generation (100 MW blocks), 4800 MW available by end of study
  - No REC credit if RPS are assumed in force
  - Costs includes any production tax credit, transmission, and firming and integration costs
- Geothermal (14 MW blocks) available 2011, 424 MW (382 MWa) by end of study
- Woody biomass (25 MW), available 2014, 830 MW by end of study
- Advanced nuclear (1,100 MW), available 2023, 4,400 MW by end of study

- Supercritical pulverized coal-fired power plants (400 MW), available 2016
- Integrated Gasified Combined-Cycle combustion (518 MW) available 2023, with carbon capture and sequestration
- Wind imported from Montana, with new transmission, available 2011, 1,500 MW by end of study
- Five classes of demand response, 2,000 MW available by end of study, 1,300 MW of this limited to 100 or fewer hours per year of operation

As mentioned in the discussion of existing renewable portfolio standard resources, resources that have a very good chance of completion are included in the base level of resources. This includes certain other thermal resources having high probability of completion. They are not modeled explicitly as new resources.

Table 9-4 shows relatively new resources that are not listed in Table 9-1.

Table 9-4: Recent Construction

project	capacity (MW)	fuel type	in-service month
Arrowrock 1 - 2	15	Hydro	Jun 2010
Bettencourt Dry Creek Dairy	2.25	Biomass	Sep 2008
Big Sky Dairy	1.42	Biomass	2009
Cassia	29.4	Wind	Feb 2009
Danskin (Evander Andrews) CT1	170	Natural gas	Jun 2008
Double A Dairy	4.26	Biomass	2009
Flathead County Landfill	1.6	Biomass	April 2009
Grays Harbor Energy Facility (Satsop)	650	Natural gas	Jul 2008
Mill Creek Generating Station	150	Natural gas	Dec 2010
Mint Farm	319	Natural gas	Jan 2008
Mountain Home	42	Wind	Sep 2008
Raft River I	15.8	Geothermal	Jan 2008

In order to keep the analysis manageable, only new resources that are found to be cost-competitive and of significant potential[6], or required by law, are considered in the model. The regional portfolio model evaluates large numbers of possible portfolios under many scenarios and requires several computers and significant time to develop a portfolio. The number of generation resources in the model affects the time required for a study. Consequently, small amounts of new micro-hydropower generation, solar thermal, and other smaller sources are assumed to be captured under renewable portfolio standards in the states.

System Flexibility and Capacity Requirements

Energy balance is central to economic risk and has been the focus of Council risk assessment. Regional power crises of the past were associated with energy shortages and surpluses. Examples include the hydropower generation insufficiency of the early 1970s and the 2000-2001 West Coast energy crisis. Overbuilding thermal power plants in the late 1970s and the unprecedented rate increases and financial failures that ensued illustrate the dangers of overbuilding.

[6] The cutoff for consideration is around 300 MW of cost-effective potential by 2030.

The power system has other requirements, however. Power system balance on the sub-hourly level is critical to integration of wind and other variable resources. Without providing for system peaking and flexibility requirements, the region risks forgoing resources that can reduce energy risk. Chronic shortages in the special-purpose markets for resources that meet these requirements may result, or the power system otherwise may become inefficient.

In modeling wind power, an additional integration and firming cost is added to that of direct wind-turbine costs. The model does not include any additional resources that may be required to provide these services. Currently, it is unclear how much, or even whether, incremental generation resources may be required for this purpose. The action plan of this power plan supports work underway by the regional Wind Integration Forum to evaluate those requirements.

The model uses economics to evaluate peaking requirements and contribution. The model can discern economic value that arises from hourly events, such as forced outages. Economic value determines whether the model will build a power plant. Any value beyond that necessary to cover plant costs lowers the system cost, so the model would choose to add it. Traditional reliability and adequacy assessments of capacity requirements ignore fuel prices or operation costs. It is assumed that if the region needed capacity to meet an unforeseen circumstance, fuel price would not be an issue. If prices ***were*** considered, however, very high electricity prices would result. Of significance here is that the model would build more resources in this situation specifically to avoid exposure to these high prices.

Moreover, the Council relies on metrics that the regional adequacy forum has adopted. This forum, a consortium of utilities, regulators, and customers, has produced deterministic energy and capacity load-resource balance standards that incorporate much of what the region has learned about resource adequacy.

The model incorporates the forum's annual energy metric directly into resource-selection decisions. If a planned resource would not be constructed because the model forecasts that the resource would not be economic, the model forecasts the region's needs according to the forum's energy balance standard. If the calculation indicates the region is in danger of resource inadequacy, construction of the least-cost, planned resource continues.

Finally, any plans the model produces that the Council would recommend are compared to the forum's energy and capacity standards. Experience has shown, however, that economic adequacy produces plans that meet energy adequacy and peaking requirements. The plan addresses flexibility further in Chapter 12.